AR76

Winspear Business Reference Library
University of Alberta
1-18 Business Building
Edmonton, Alberta T6G 2R6

Tempest
ENERGY CORP.

2004 ANNUAL REPORT

CONTENTS

2 Highlights
4 Presidents Message
8 Exploration and Operations Review
21 Operations Statistical Review
30 Reserves Engineer's Report
31 Management's Discussion and Analysis
53 Management's Report to Shareholders
54 Auditors' Report to Shareholders
55 Consolidated Financial Statements and Notes
68 Corporate Information

Accelerating value per share

Tempest Energy Corp. is a Calgary, Alberta based oil and natural gas company that is achieving strong operating and financial growth through exploration of internally generated, high working interest prospects at two core areas, plus a third emerging exploration area. Tempest had average production in 2004 of 3,634 boe per day, with growth achieved primarily through exploration and development drilling.

Tempest is a publicly-traded company listed on the Toronto Stock Exchange (TSX) under the symbols TMY.A and TMY.B. At December 31, 2004 there were 19.1 million Class A and 653,476 Class B common shares issued and outstanding.

2 CORE AREAS
243,817 NET ACRES
OVER 700 SQ. KMS. OF 3-D SEISMIC

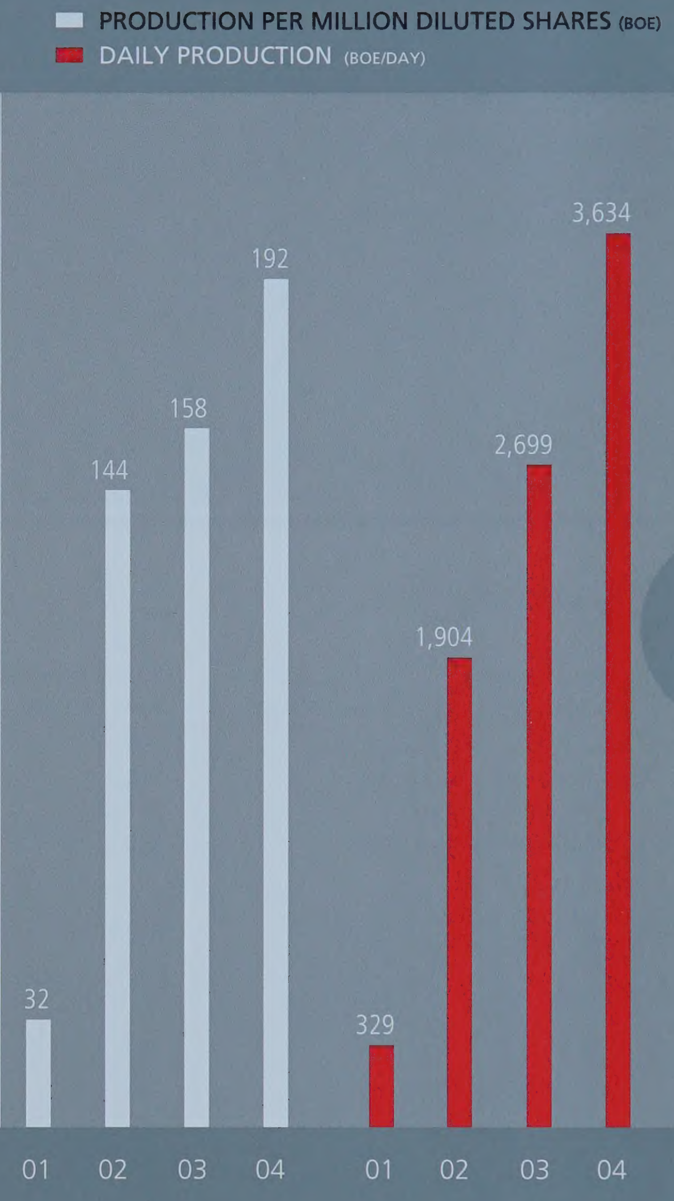
Year-over-year production growth of 35 percent in 2004 was generated 93 percent through the drill bit, continuing Tempest's record of organic growth. Tempest has evolved into a better balanced, more diversified Company, increasing its asset base from three producing properties in late 2003 to 12 in early 2005. The production mix includes low-operating-cost natural gas, high-netback light oil and medium-gravity crude.

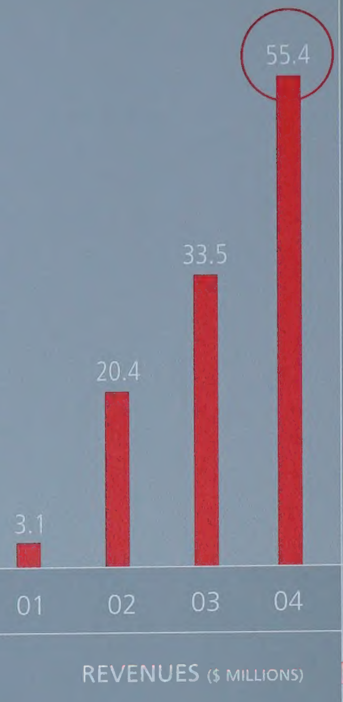
OVER 25 MMCF PER DAY
PROCESSING CAPACITY
HUNDREDS OF KILOMETRES OF PIPELINE

Tempest's management team is focused on sustaining the Company's ability to grow. Tempest continually expands its undeveloped land base, creating new plays and broadening existing play areas. Commitment to 3-D seismic has generated new play concepts, expanded existing projects and reduced technical risks, improving capital efficiencies. Strategic infrastructure enables timely tie-in of new production and is reducing unit costs of new reserve additions.

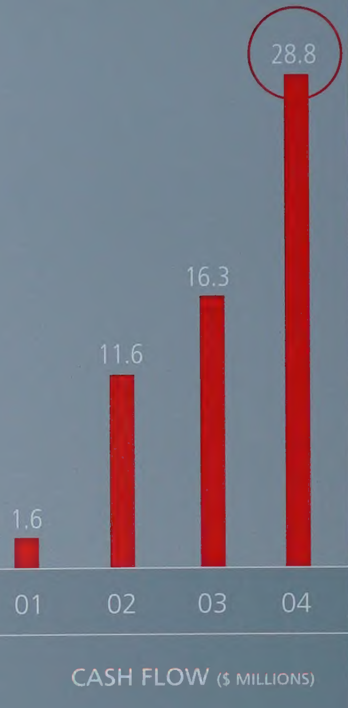
100 PLUS
DEFINED LOCATIONS

In 2005 Tempest will lever its multi-year exploration and development inventory to continue organic growth. The Company's 49-well drilling program is 60 percent exploration-weighted and 70 percent natural gas-weighted. Targets span the risk-reward spectrum, from low-risk oil exploitation and natural gas recompletions in new zones, and the expanding Keg River light oil play, to deep, high-impact natural gas tests in Alberta's West 5 region.





REVENUES ($ MILLIONS)



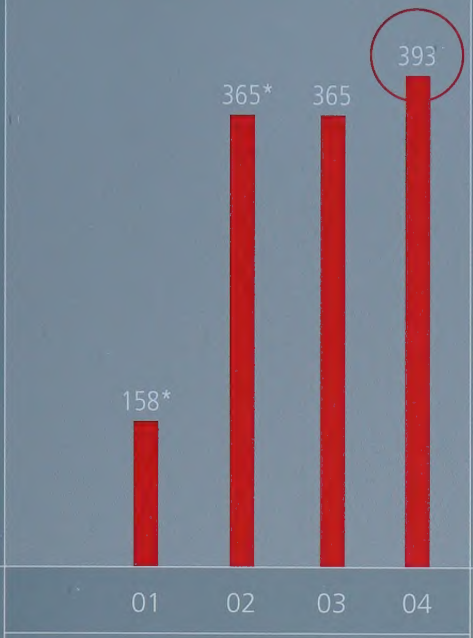
CASH FLOW ($ MILLIONS)

HIGHLIGHTS

FINANCIAL

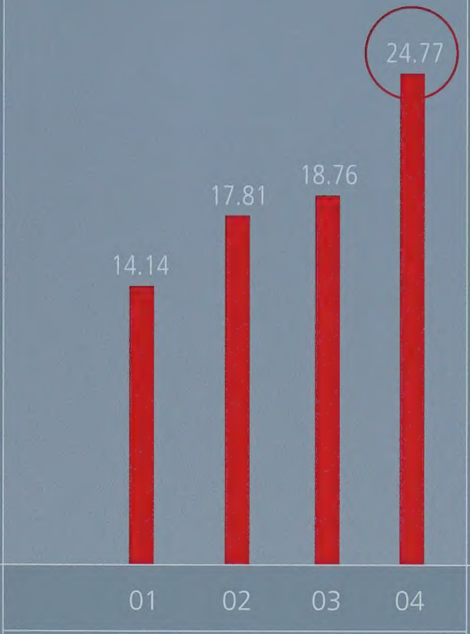
($ thousands, except per share data)	**Twelve Months Ended Dec. 31, 2004**	Twelve Months Ended Dec. 31, 2003	Twelve Months Ended Dec. 31, 2002
Petroleum and natural gas sales	**$ 55,363**	$ 33,473	$ 20,364
Cash flow from operations	**28,797**	16,275	11,633
Per basic share	**1.55**	0.97	0.92
Per diluted share	**1.52**	0.95	0.88
Net income	**4,171**	967	1,746
Per basic share	**0.23**	0.06	0.14
Per diluted share	**0.22**	0.06	0.13
Total assets	**123,358**	89,254	55,004
Total liabilities	**62,254**	45,212	23,582
Working capital (deficit)	**(32,167)**	(20,859)	(5,085)
Capital expenditures	**50,962**	47,499	34,316
Shares outstanding			
Class A	**19,060,810**	17,370,319	14,737,933
Class B	**653,476**	653,476	653,476
Options	**1,499,004**	2,076,704	2,116,867
Basic shares (weighted) *	**18,513,240**	16,756,145	12,651,760
Diluted shares (weighted)	**18,924,314**	17,067,422	13,257,405

* Class B shares are fully converted in basic calculation (see the Equity section in the MD&A for the calculation).



RESERVES PER MILLION SHARES (BOE)

*Calculation based on P + 1/2 P



FIELD NETBACKS ($/BOE)

OPERATING

	Twelve Months Ended Dec. 31, 2004	Twelve Months Ended Dec. 31, 2003	Twelve Months Ended Dec. 31, 2002
Production			
Crude oil and NGLs (bbls/day)	**1,388**	1,848	1,475
Natural gas (mcf/day)	**13,473**	5,102	2,575
Barrels of oil equivalent (6:1) (boe/day)	**3,634**	2,699	1,904
Prices			
Crude oil and NGLs ($/bbl)	**$ 46.13**	$ 30.04	$ 30.87
Natural gas ($/mcf)	**6.47**	6.18	3.99
Barrels of oil equivalent (6:1) ($)	**41.63**	33.98	29.30
Operating costs ($/boe)	**6.47**	5.66	4.82

PRESIDENT'S MESSAGE

Our four years spent organically building Tempest Energy Corp. culminated with significant increases in key benchmarks – cash flow (77percent), production (35 percent) and proved plus probable reserves (20 percent). These accomplishments were again achieved primarily through exploration and development of internally generated prospects. Tempest has just 19.1 million Class A shares outstanding and the 21 percent growth in production per share strengthened our ability to continue growing with enhanced capital efficiency.

With 325 net sections of undeveloped lands focused in two core areas, new 3-D seismic covering over 200 square kilometres, control of key operated infrastructure and over 50 drill-ready locations for 2005, Tempest is currently on track to achieve its forecasted average volumes of 4,500 boe per day this year.

As a company matures past the emerging stage into a junior E&P, it becomes increasingly important to enhance and adhere to a sound growth strategy. Where emerging companies are almost entirely opportunity driven, maturity brings with it a responsibility to improve the company's risk profile. In these respects as well, Tempest is a substantially better company. We expanded from an initial focus on medium-gravity oil into light oil and natural gas.

In late 2003, Tempest had only three significant producing properties. Today, we have 12, including our Red Earth light oil play, which has repeatedly exceeded our expectations as it expanded from a modest pool extension into an oil pool underlying numerous sections of land. Our growth in natural gas production to 13.5 mmcf per day in 2004 has increased our natural gas weighting to approximately 62 percent from just 32 percent in 2003. These successes have enabled Tempest to keep operating costs low and netbacks high. Greater diversity is adding strength and flexibility to support profitability over the longer term.

2004 in review

In 2004, we demonstrated the strength of our asset base and technical team's ability to consistently find new reserves, exercise cost discipline, resolve challenges and keep the Company on its path of organic growth. Recent wells were expeditiously tied-in, including in our seasonal-access northern properties; our drilling program achieved a high success rate; key infrastructure was commissioned at several properties; a mid-year optimization/exploitation program boosted volumes at low capital cost; undeveloped lands continued to be expanded; and a small acquisition consolidated our position around Fort Saskatchewan.

Tempest's 2004 capital program added 935 boe in daily volumes, net of declines, including 8.4 mmcf per day in new natural gas production. The Company's year-end production increased by more than 51 percent, with 93 percent of growth achieved through the drill bit. Tempest's average volume growth to 3,634 boe per day, low operating costs, high netbacks and favourable commodity prices combined to generate cash flow of $28.8 million ($1.52 per diluted share), well above our initial target. Tempest has demonstrated the ability to be operationally solid as we are drilling in moderate-risk areas characterized by shallow to medium depths, high initial rates, quick pay-out and strong netbacks. With a proven track record in the front-end development of properties, Tempest is ready for an aggressive period of drilling, which includes higher reserve-life opportunities; balancing growth and enhancing size through strategic acquisitions and expanding exploration to deeper multi-zone targets.

Successes in the field

The Central Area remained the foundation of Tempest's production, averaging approximately 2,518 boe per day in 2004. Last year's corporate capital expenditures of $51 million included $21 million for drilling and completions, $16 million for new facilities, $6 million for an acquisition, and the balance for land and seismic. We added natural gas volumes at Chipman, Looma/Joarcam, Fort Saskatchewan and Otter, while the multi-year exploration and development program at Red Earth increased our production of light crude oil. In 2004 Tempest drilled 32.8 net wells, 80 percent of which were exploratory, resulting in an overall drilling success rate of 87 percent.

While enjoying near-term production gains, Tempest's capital program was weighted to sustain future growth at higher capital efficiency. This includes our investment in facilities, many of which were sized for substantially higher volumes, and our commitment to 3-D seismic, key to building Tempest's prospect inventory. Already we are seeing the benefits of infrastructure through faster and less costly tie-in of new wells. Towards year-end, Tempest launched an additional round of 3-D seismic, shooting over 200 square kilometres throughout the Central Area, a process that continued in Q1, 2005.

We were very pleased with Tempest's field metrics in 2004. Operating costs, which averaged $6.47 per boe, reflected additions of high-rate, low-cost natural gas wells, more efficient use of infrastructure, new light oil volumes and ongoing reservoir management of Chipman oil production, while absorbing the cost escalations due to the general increased activity in the oil and gas industry. The 2004 average continued to place Tempest among the most efficient in its peer group. Combined with strong commodity prices, Tempest received an average field netback of $24.77 per boe, our best performance to date.

Financial flexibility

Tempest funded its $51 million capital program (including a $6 million acquisition in Q3) through internal cash flow, $11 million in remaining proceeds from a flow-through share issue in late 2003 and moderately increased bank lines. During the year we syndicated our debt, with the CIBC becoming our lead banker. Reflecting our larger production and reserves base, our borrowing capacity was increased to $40 million. With Q4 cash flow of $6.5 million, Tempest's debt to annualized cash flow ratio was 1.2 times despite the year's record capital program. Net income grew substantially year-over-year to $4.2 million ($0.22 per diluted share) for 2004.

Tempest continued to exercise discipline regarding shareholders' interests. Our policy of limiting issuance of new equity through our emerging phase has helped ensure that Tempest's growth was accretive. At year-end 2004 we had only 19.1 million Class A shares, fewer than most emerging and junior Canadian oil and natural gas producers.

Tempest's 2004 cash flow of $1.52 per share (diluted) represents year-over-year growth of 60 percent. Tempest also increased its production per share to more than 192 boe per day per million shares outstanding in 2004, placing us in the top quartile among junior producers. Discipline in issuing shares provides Tempest with the underlying ability to leverage its future growth when the opportunity arises.

Red Earth light oil

Of all Tempest's organic growth programs to date, none has surpassed expectations with its expanding scale and out-performance as much as the Keg River light oil play at Red Earth. Over three winter seasons of steady effort, Tempest has built this play from a selective oil pool extension into a multi-section play with material corporate impact. As of March 2005 we have participated in a total of 16 (10.0 net) producing wells with a current average net production per well of 90 boe per day.

Net Keg River production at the end of Q1, 2005 will be approximately 1,000 barrels per day of high-quality, premium-priced crude oil with long reserve life potential. With 14 net sections of undeveloped lands (including seven sections at 100 percent working interest), plus a township of 3-D seismic coverage at Red Earth, Tempest foresees several seasons of drilling and production growth ahead. Tempest commissioned an independent reservoir study in late 2004 that suggests gross original oil-in-place on lands in which Tempest has a working interest is more than 11 million barrels. Potential recovery factors under full waterflood are estimated at 44 percent.

Subsequent drilling has proven significant extensions to the pool beyond those contemplated in the study, including extensions onto Tempest's 100 percent lands. Tempest currently has 1.6 million barrels of reserves booked in this pool, which does not reflect the upside from the winter 2004-2005 drilling, future drilling prospects or a successful waterflood. Tempest and its partner are initiating water injection and are evaluating the best alternatives for full waterflood implementation.

Reserves and F&D costs

Last year's reserve reports reflected the industry's recent adoption of the more stringent reserve reporting standards of National Instrument (NI) 51-101. At the time, Tempest expressed the belief that gaining a full year's production history on newly producing wells could result in future upward revisions to reserves. The combination of positive revisions plus that year's investment in further new wells was expected to lead to more "normalized" finding and development (F&D) costs going forward. This process began to emerge in 2004.

Tempest's June 1, 2004 reserves evaluation included material increases in proved reserves compared to December 31, 2003, as well as an increase in the ratio of natural gas reserves. The December 31, 2004 evaluation confirmed this trend. Tempest's overall reserves of 7.4 million boe proved plus probable included an increase, net of 2004 production, of 1.2 million boe or greater than 19 percent over year-end 2003. Combined with Tempest's 2004 capital expenditures of $51 million, this resulted in an average F&D cost of $16.89 per boe of proved reserves added.

Also important is that Tempest's reserves at year-end 2004 are more diversified, including four major natural gas properties plus light oil, to augment our older base of medium-gravity crude oil. This helps to maximize Tempest's discounted net asset value and current cash flow. Our higher front-end cash flow will be employed to continually improve the quality of our assets and incrementally notch up our reserve life, which at year-end 2004 was 5.6 years proved plus probable.

2005

Strategy – Today, Tempest is positioned with a critical mass of production, infrastructure, land and new prospects, which are more diversified in number and play types than in the past. Working from this base, we foresee continued improvements in capital efficiencies through adding production and reserves near established infrastructure. In 2005, adhering to our key principles, we aim to achieve accelerated growth per share.

Our approach in 2005 will be four-pronged:

- Target multi-zone, 3-D seismic-defined natural gas opportunities primarily in the Central Area;
- Continue exploration and development of the expanding Red Earth light oil play, as previously discussed;
- Accelerate work to develop a third core area; and
- Actively seek opportunities for acquisitions.

Tempest's planned 2005 49-well drilling program will be approximately 60 percent exploration-weighted and 70 percent natural gas-weighted. Our founding principles of high average working interest (now at 87 percent), operatorship (now at over 90 percent of production) and continuous expansion of our land base (now at 325 net sections) remain unchanged.

Third core area – Over the past two years Tempest has quietly worked to develop new plays that offer potential to mature into a third core area. In west-central Alberta we are prospecting for multi-zone, medium-depth natural gas. Through small Crown sales and farm-ins we have gained a foothold of land at both plays in these challenging and competitive, but highly prospective regions.

At Cygnet, a second 100 percent working-interest well drilled in Q1, 2005 has confirmed potential for a multi-well gas drilling program with down-spacing potential on Tempest's acreage. The first well was successfully production tested at a stabilized rate of 250 mcf per day with the second well currently awaiting completion. Depending on test results, both wells could be tied-in before year-end. Tempest's first exploration well spudded in February, 2005 at Edson was dry and abandoned. Additional drilling could occur at both properties before year-end. Meanwhile, we will work to increase our position in the greater region.

Acquisitions – Tempest recognizes the potential growth advantages from carefully selected acquisitions. In late 2004 we created a dedicated acquisitions team, enabling careful evaluation of candidate assets and companies while allowing our exploration and operations teams to focus on their core tasks. We will consider three types of acquisitions: consolidations that augment or improve efficiencies of existing plays and properties; transactions that improve key metrics; and strategic acquisitions that provide entry into a new area.

Western Canada's acquisitions environment remains intensely competitive, with asset prices supported by high commodity prices and strong buyer interest. Tempest's asset prospecting will be selective and financially prudent. We are not pursuing growth for growth's sake. Our priority in all cases will be long-term growth per share.

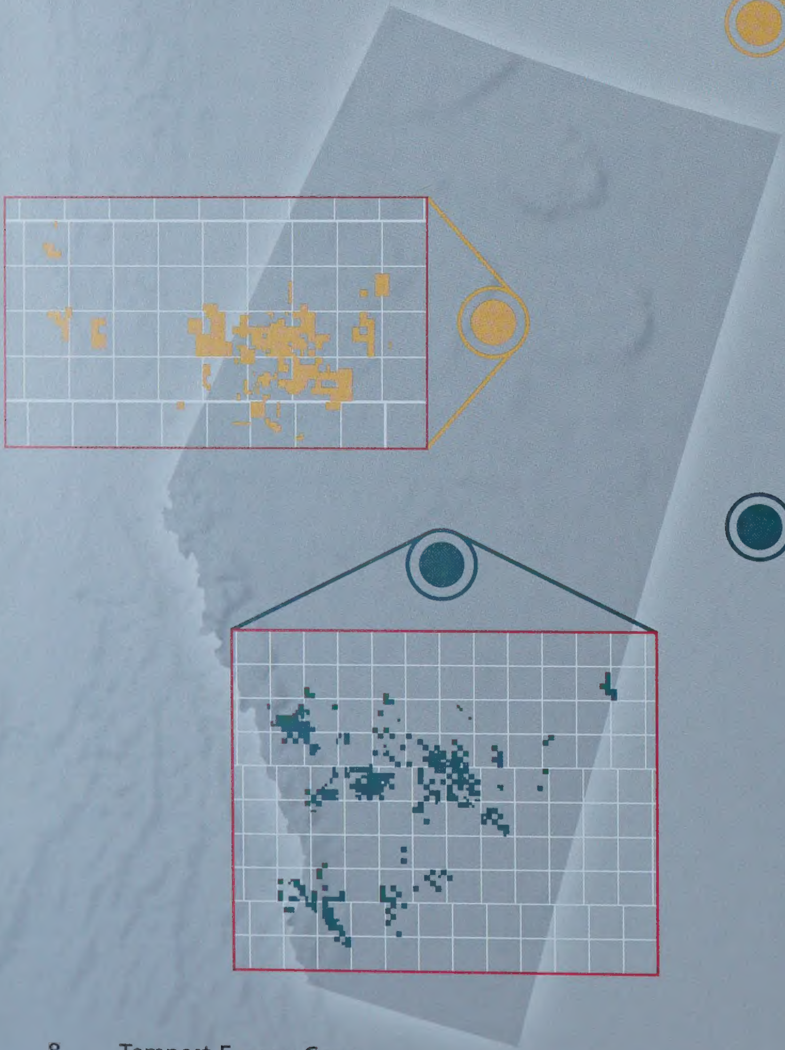
Key forecasts – Tempest's planned 2005 capital budget of \$40 to \$50 million is slightly lower than 2004 expenditures. This reflects increasing capital efficiencies, as both the percentage and the amount assigned to drilling and completions will be higher than in 2004. Under this budget Tempest plans to achieve average 2005 production of 4,500 boe per day. Under the assumed price and production scenarios, Tempest estimates 2005 cash flow of \$40 million (up to \$2 per diluted share). We aim to continue accretive growth, targeting production of 250 boe per day per million common shares in 2005. The 2005 capital budget is based on assumed 2005 average commodity prices of US\$40 per barrel WTI and Cdn\$6 per mcf of AECO natural gas.

Acknowledgements

My sincere thanks and deep appreciation go to each member of Tempest's management team, including not only the veterans who participated in the Company's founding and early growth, but those who have recently joined to augment our skill-sets as we grow to the next level. Thanks also to each member of Tempest's head office staff and our growing team of field personnel, who are becoming a larger component of the Company as we add infrastructure at our expanding base of properties.

A. Scott Dawson, P.Eng.
President, Chief Executive Officer and Director
March 15, 2005

EXPLORATION AND OPERATIONS REVIEW

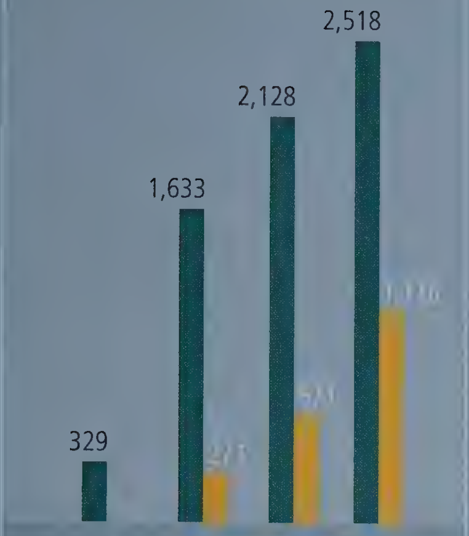


NORTHERN CORE AREA

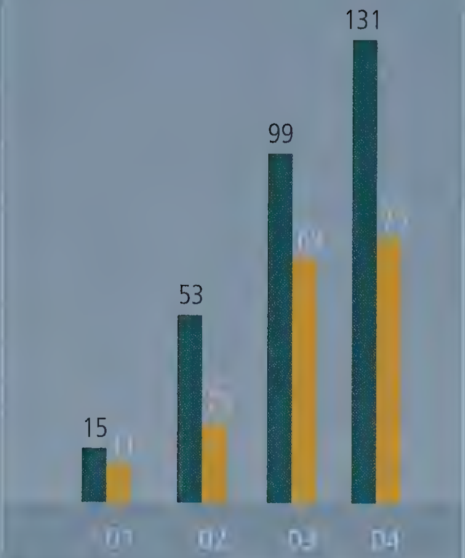
- Successful exploration area for shallow natural gas and longer-life light oil
- 2004 production averaged 1,116 boe per day, or 31 percent of Company volumes
- Growing Keg River light oil play at Red Earth
- High netbacks and low operating costs on natural gas and oil production
- Continued natural gas potential
- 74,969 net undeveloped acres of land at year-end 2004
- Major Q1 2005 Keg River oil exploration and development program underway

CENTRAL CORE AREA

- Average 2004 production of 2,518 boe per day
- Low-risk, multi-zone targets at less than 1,000 metres, with opportunities for uphole recompletions
- Fast, low-cost drilling, high initial production rates, rapid cost recovery
- 131,000 net undeveloped acres of land at year-end 2004
- Over 200 square kilometres of new 3-D seismic as of early 2005
- Low operating costs, established Company infrastructure, easy tie-in of new production
- Further natural gas volume growth



PRODUCTION BY AREA
(BOE/DAY)



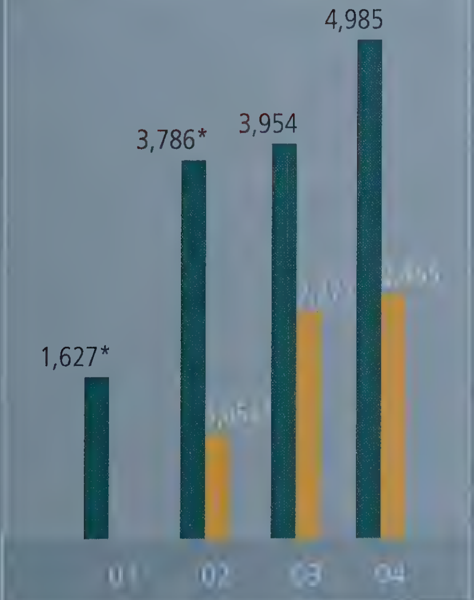
UNDEVELOPED LAND
(000 NET ACRES)

Central Area production commenced with Tempest operated oil wells at Chigwell, but extensive 3-D seismic has driven substantial natural gas drilling and production volumes. The Northern Area generates both oil and natural gas production with recent focus on Tempest's exciting Peace River Trout oil play.

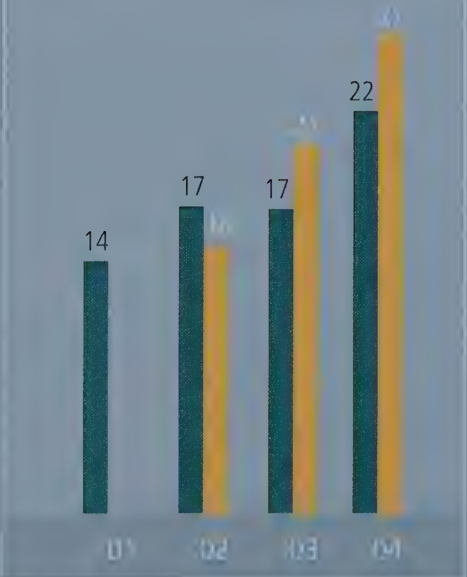
Land is vital to every exploration company's future. Tempest continues to build its undeveloped land holdings in both core areas.

🟧 NORTHERN AREA

🟩 CENTRAL AREA



PROVED AND PROBABLE RESERVES
(MMBOE)
*Calculation based on P + 1/2 P



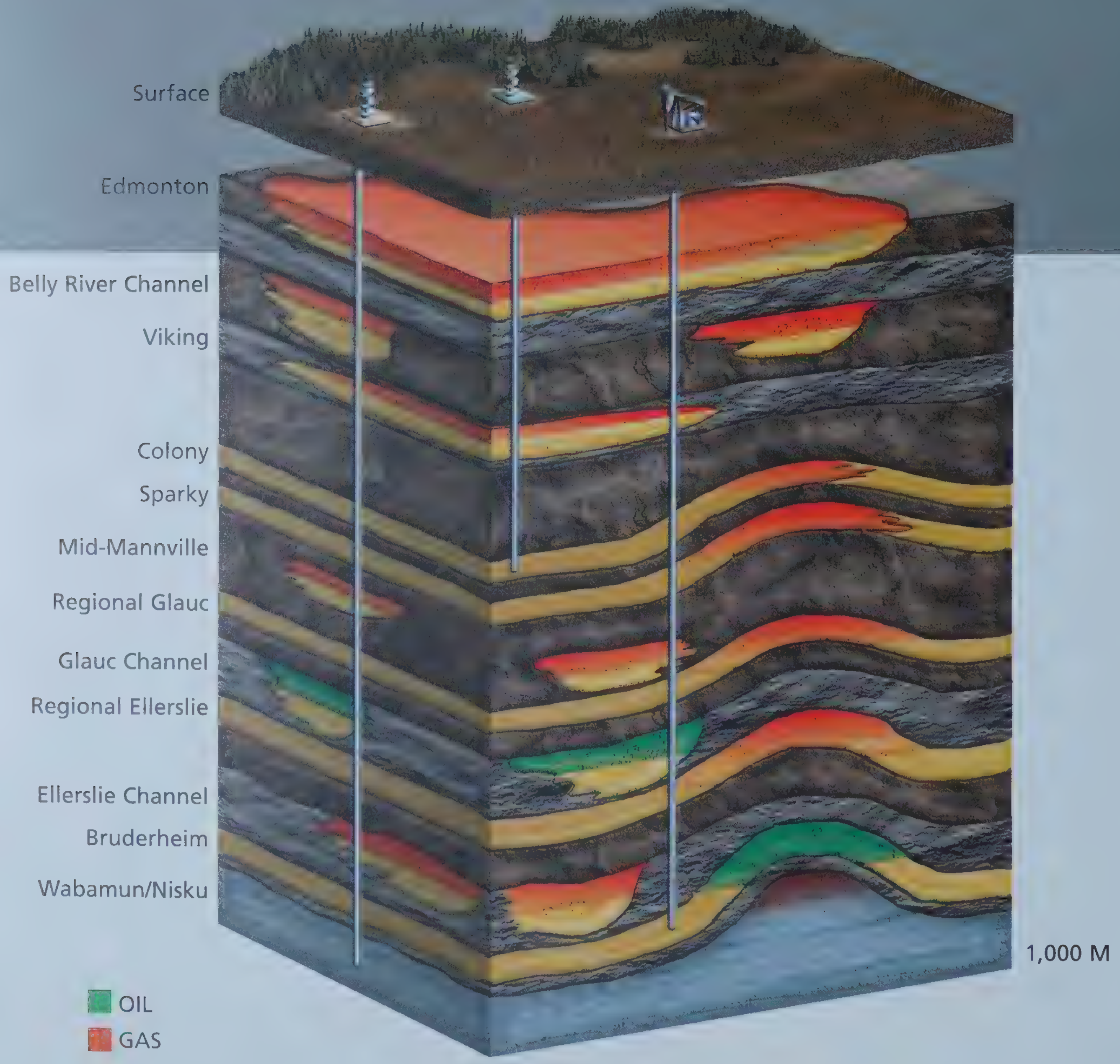
FIELD NETBACKS
($/BOE)

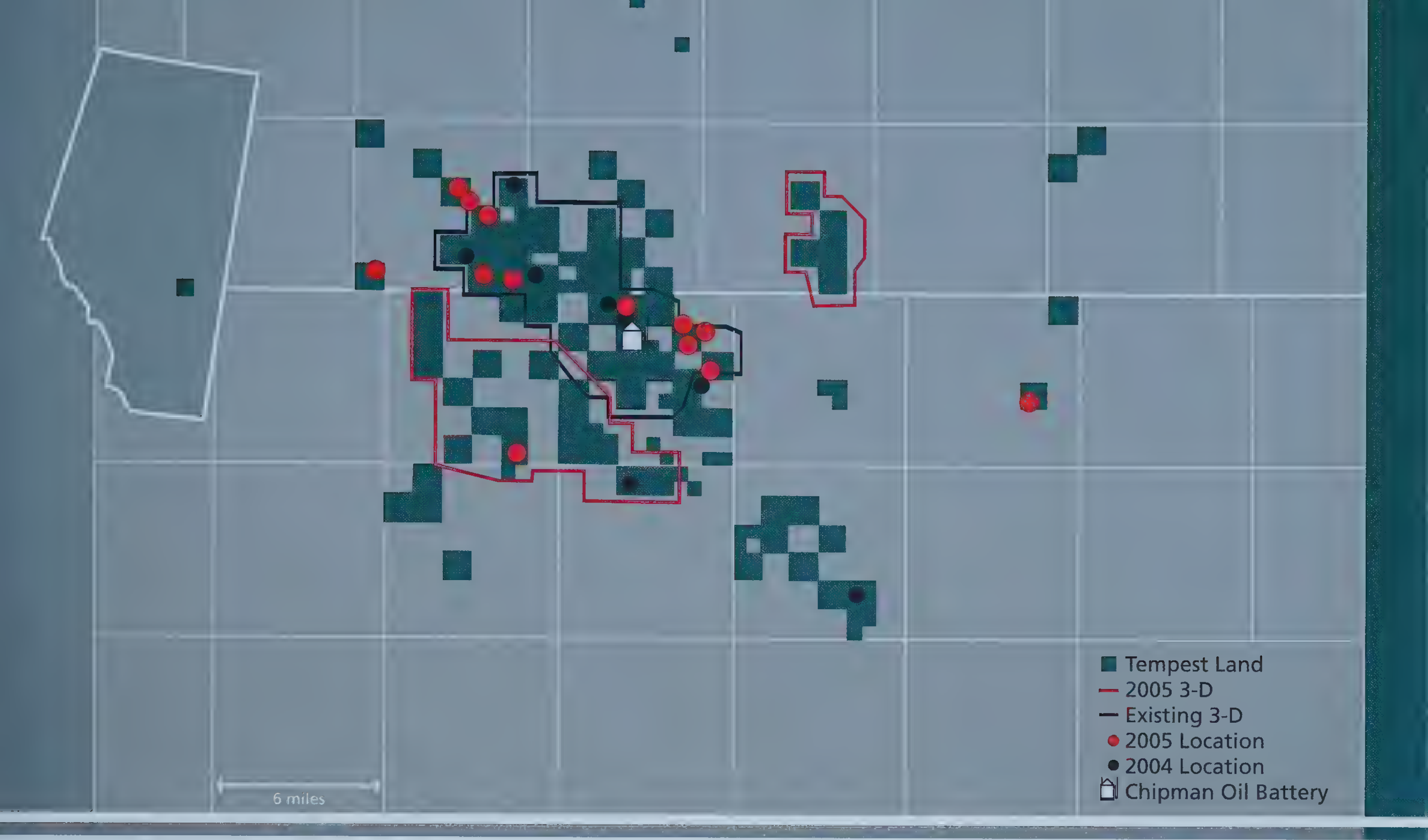
Tempest had reserves growth in both core areas in 2004. 2002 marked the entrance to and beginning of production in the Northern Area.

Increased field netbacks in both areas reflect substantially higher prices for crude oil and slightly higher natural gas prices during the year.

Central Area

Tempest's Central Area has rapidly expanding natural gas plays and a steady base of medium-gravity crude oil production. Growth is driven by Tempest's accumulating resident knowledge developed through repeated drilling, major commitment to 3-D seismic, expanding land base and construction of key facilities to enable capital efficient tie-ins of new production. Tempest's geological recognition has increased from eight prospective zones three years ago to 15 zones in 2004. At Looma/Joarcam, four discoveries came in four separate zones. At Fort Saskatchewan, three discoveries were in three separate zones. New zones were also found at Chipman.





CHIPMAN

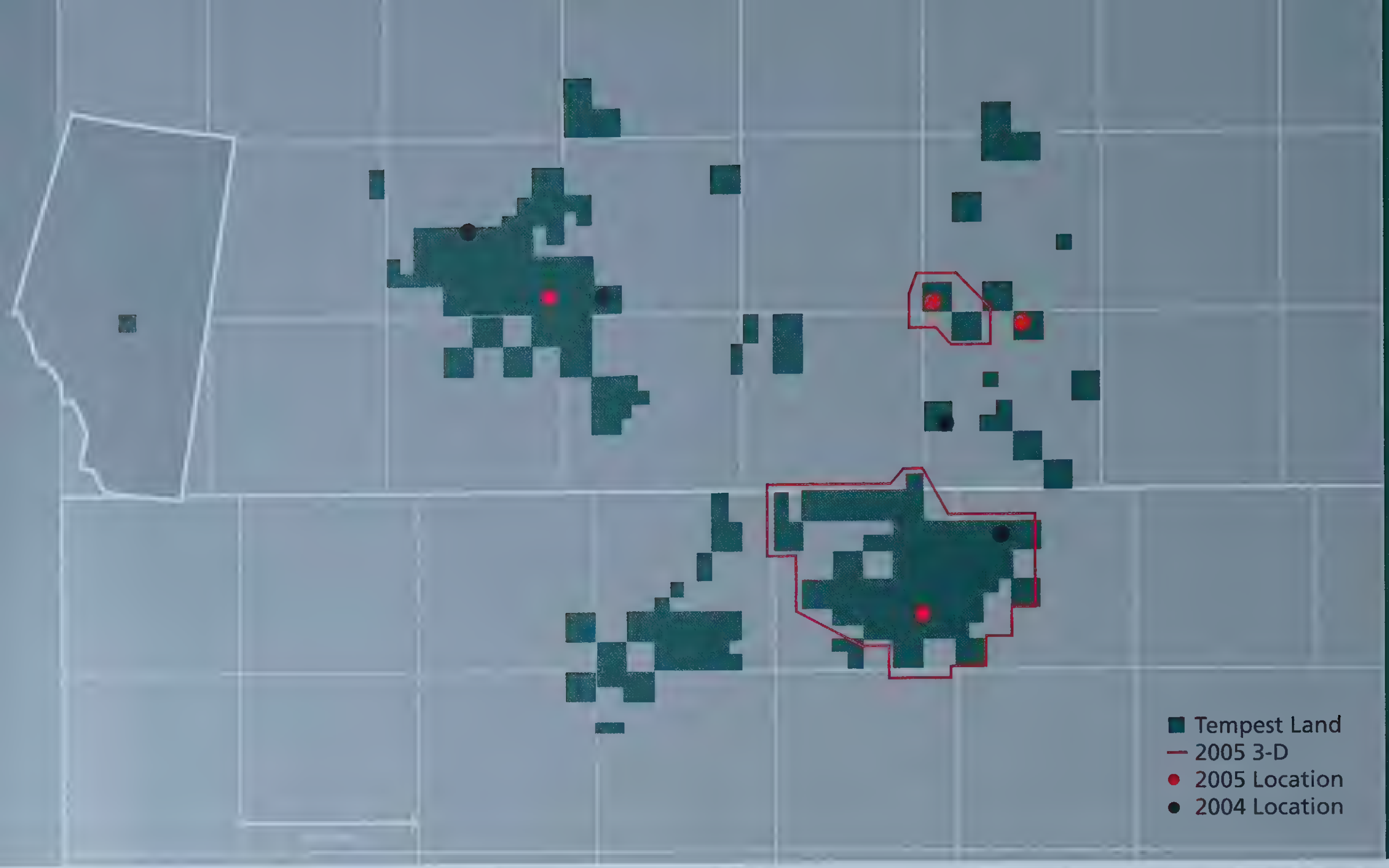
Tempest's original, medium-gravity Glauconitic oil play at Chipman remains a major component of the production base, with year-end 2004 volumes of 973 barrels per day from 23 producing horizontal wells. Since 2003 Chipman has become a significant natural gas play. An initial focus on recompleting existing oil wells for uphole Mannville natural gas has graduated into a full-fledged exploration program. Six new natural gas wells in 2004 grew year-end production to 3 mmcf per day.

Strong crude oil prices helped to generate oil netbacks averaging $24.53 per barrel of production in 2004. At mid-year Tempest undertook a low-cost optimization/exploitation program to limit operating costs and manage the declines of producing Glauconitic oil wells. The Company installed high-rate, down-hole pumps at five producing wells and performed other optimization work that appears to have stabilized annual production declines of many of the Glauconitic wells at roughly 10 percent. Tempest has several more Glauconitic horizontal development wells in inventory, which may be drilled in 2005 or 2006.

Recognizing that seismically defining the discrete, multi-zone natural gas pools at Chipman leads to higher success rates and better well productivity, Tempest in 2004 committed to fully covering its lands with 3-D seismic.

As the Chipman gas play grew, Tempest began shifting from a custom processing approach to Company-operated infrastructure. Tempest is evaluating the installation of a metering station on a regional sales line, a six-kilometre gathering system and compression with design capacity of 10 mmcf per day.

For 2005 Tempest sees strong potential for repeatability of its natural gas successes throughout its 71-section Chipman property. The 2005 capital budget includes funding for 15 net natural gas wells. Tempest will pursue additional Mannville Group targets as well as new stratigraphic prospects in the Sparky and Upper Glauconitic that hold potential for longer-life reserves. Tempest will also remain alert for additional Glauconitic oil opportunities. Activity will pick up after spring break-up and continue through year-end.



FORT SASKATCHEWAN / REDWATER

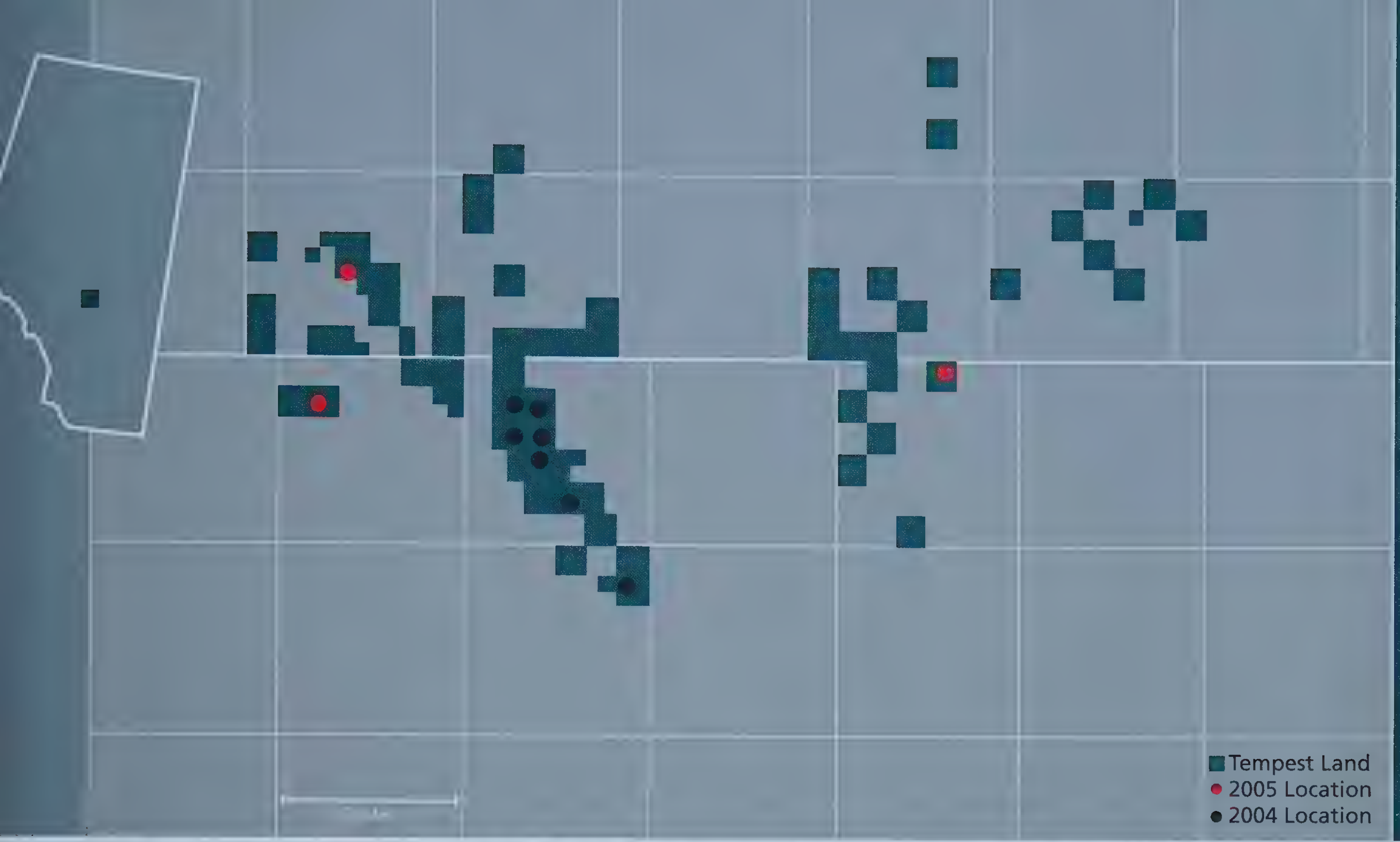
Another of Tempest's recent natural gas plays, the relatively lightly explored region around Fort Saskatchewan, is proving a tremendous opportunity that has yielded speedy growth on a level similar to Looma/Joarcam. Three wells targeting Mannville gas drilled in late 2003 and tied-in by early 2004 have generated net production of 2.2 mmcf per day.

Foreseeing further opportunities at this multi-zone play, where Tempest controls a greater than township-sized land block, the Company has commissioned a 100 percent owned and operated compression facility and metering station accessing a regional sales line. Following initial successes using a limited database of well logs and trade 2-D seismic, Tempest committed to shoot proprietary 3-D seismic over its entire 35 sections of undeveloped lands, starting in Q1 2005. This will maximize opportunities and reduce drilling risks.

In Q3 2004, Tempest conducted a consolidation-type acquisition at Bon Accord, northwest of its core Fort Saskatchewan lands, adding production of 1 mmcf per day net plus 28 sections of undeveloped lands, augmenting the Company's opportunity base.

Going forward the Company sees opportunities for growth through tapping up to 12 zones at greater Fort Saskatchewan, including the Edmonton, Belly River, Viking, Ellerslie, Glauconitic and Bruderheim as well as several Mannville horizons. Tempest has identified six net locations based on 2-D seismic and geology. However, we will utilize new 3-D seismic to confirm these locations before drilling commences in Q2 2005.

At Redwater, Tempest is proceeding at a prudent pace to explore the potential for overlooked light oil opportunities in the Bruderheim sands, as well as uphole natural gas horizons. Bruderheim wells, when successful, produce high-quality light oil from discrete, but highly productive, long-life reservoirs. A new full-cycle program has commenced, beginning with a 3-D seismic shoot covering 13 square kilometres. This year 2-3 wells are planned in a general westward shift within this property as the Company explores for both oil and natural gas opportunities.



LOOMA/JOARCAM

Following Tempest's 100 percent working interest Viking discovery in 2003, this multi-zone Cretaceous natural gas play has gone from zero production to 4.1 mmcf per day of low-cost, high-netback natural gas at year-end 2004. In early 2004 Tempest brought the discovery well on-stream, then drilled four infill wells to exploit the Viking pool, part of a larger regional Viking gas trend. The pool had proved reserves of 3.8 bcf at year-end.

Further exploration drilling at Looma/Joarcam in 2004 made discoveries in the Edmonton, Glauconitic and Ellerslie zones, with the first Ellerslie well tied-in and on-stream in December at a restricted rate of 1 mmcf per day. All area production flows through a Company-owned and operated gathering system and compressor station.

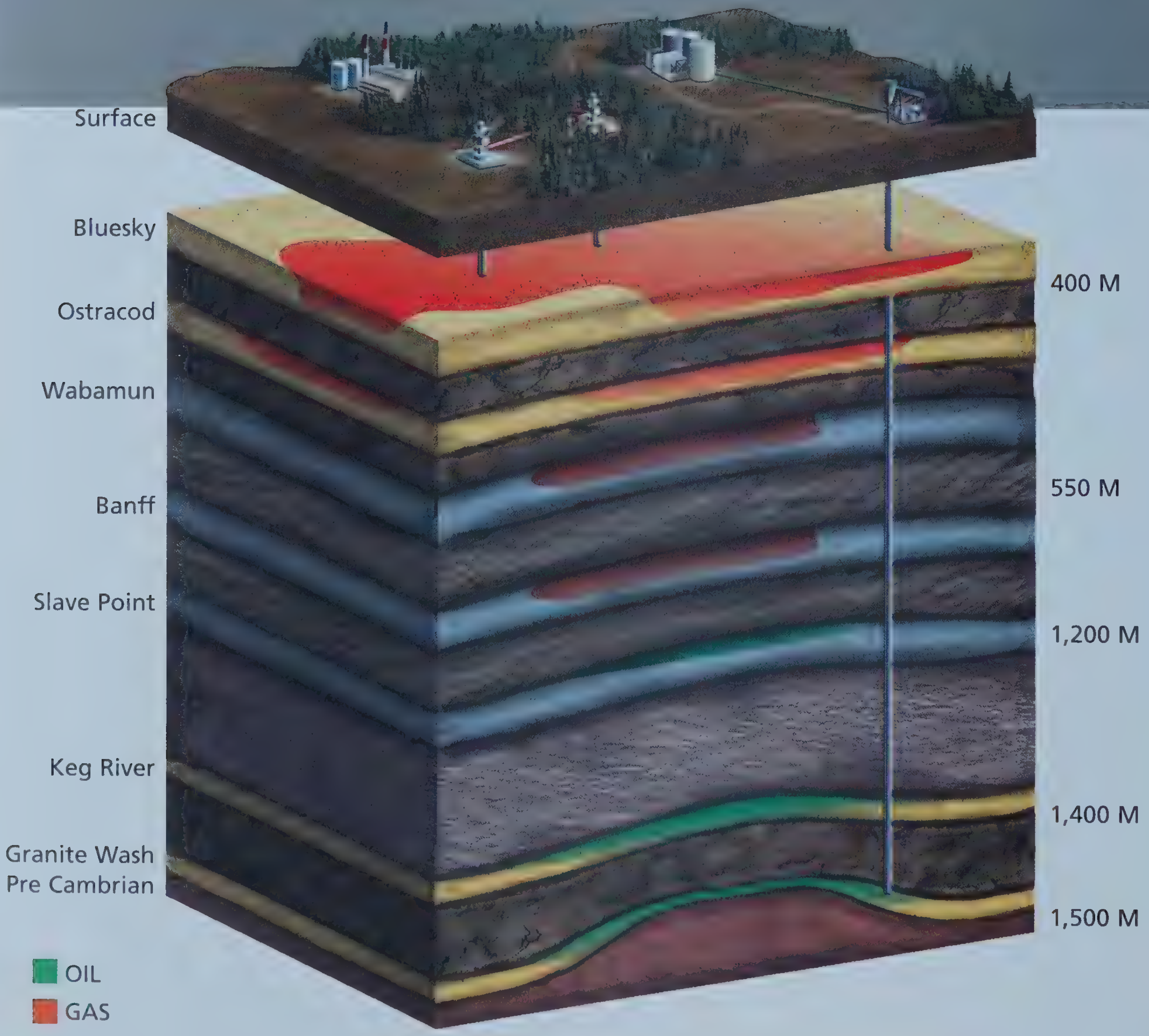
With 49 sections of undeveloped land and the first Viking pool fully developed, there is still plenty to do at Looma/Joarcam. In 2005 Tempest plans to drill four to five wells targeting Colony, Viking and Glauconitic prospects in northern Joarcam. Tempest's multi-zone successes to date suggest the value of covering this area with 3-D seismic. Tempest plans to initiate this in late 2005 or early 2006, after completing seismic programs at other properties.

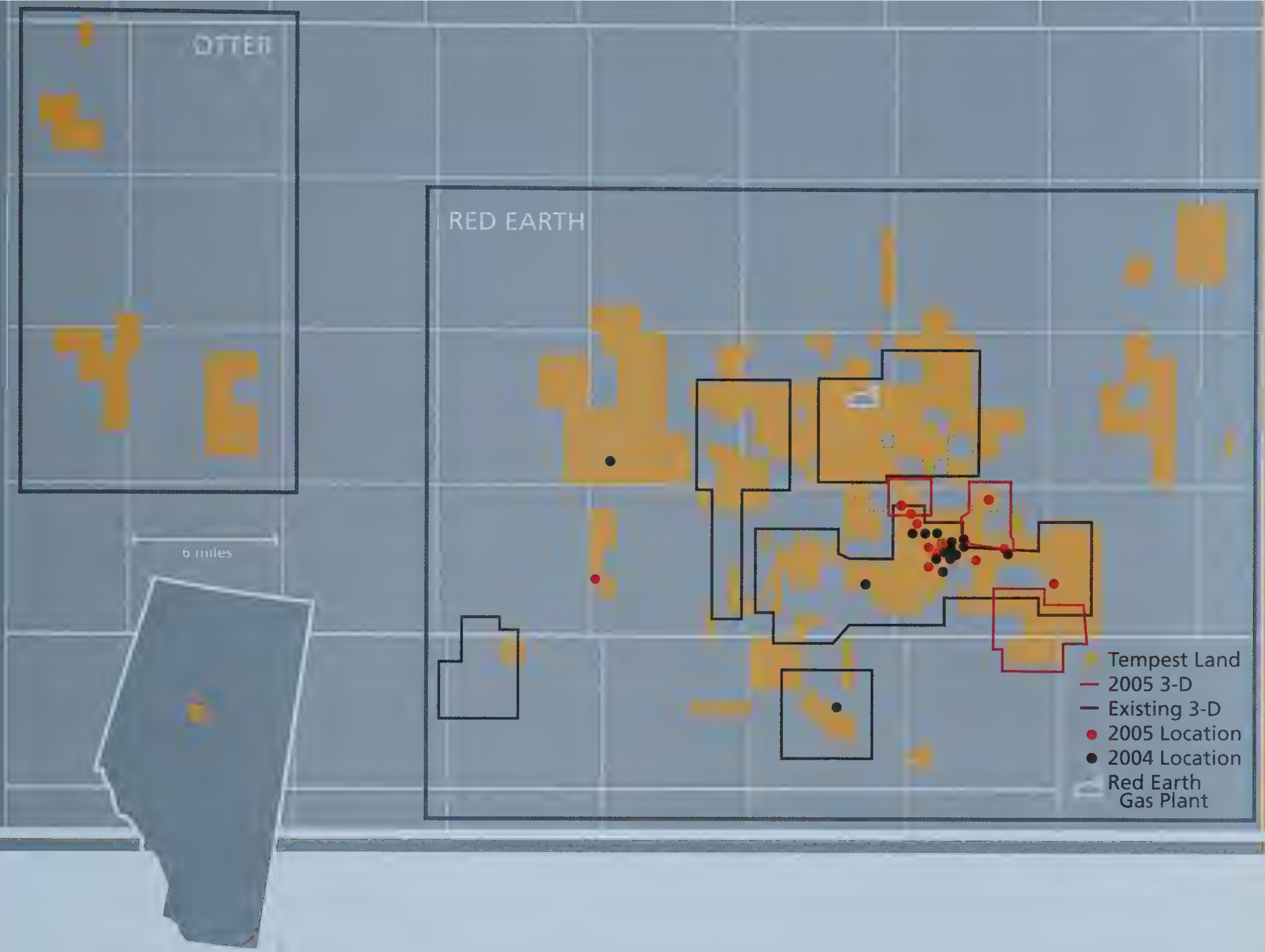
In addition, Looma/Joarcam suggests potential for coalbed methane (CBM) development. Tempest's lands lie in the heart of Alberta's Horseshoe Canyon coal fairway, and also contain Mannville coals. These are the two main CBM plays emerging in Alberta. Tempest has mapped the area, is testing two existing wellbores for CBM potential and in 2005 intends to drill at least one dedicated CBM exploration well. Though showing very high potential and growing industry interest, CBM remains at an early stage in western Canada, and Tempest will proceed with prudence.

Northern Area

Over the past two years Tempest has experienced tremendous successes in both natural gas and light oil exploration in its Northern Area. Combined natural gas and crude oil volumes grew by 95 percent during 2004, and at year-end this winter-access area was generating approximately 25 percent of the Company's production, or roughly 800 boe per day. About 70 percent of Northern Area production in 2004 was natural gas. Production of light crude oil from the multi-year Keg River play at Red Earth is growing steadily. These long-life oil reserves are rapidly developing into a Tempest cornerstone asset. During winter 2004-2005 Tempest drilled 12 additional Keg River wells.

Going into 2005 Tempest's Northern Area opportunity base included 117 net sections of undeveloped land with a current inventory of 15-20 drilling locations. Tempest's established base of production, reserves and natural gas infrastructure will facilitate measured exploration and development at reduced risk and increased capital efficiency.





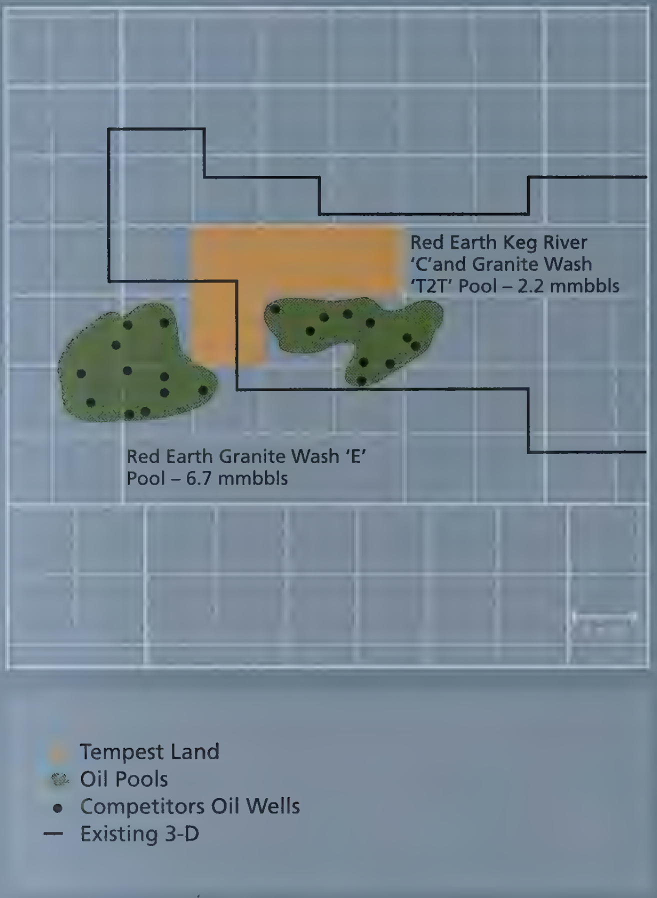
The Company's growth no longer depends on exclusively higher-risk drilling. Instead Tempest plans to pursue a balance of high-graded, carefully selected light oil and natural gas exploration and development prospects. In total, the Northern Area will receive approximately 30 percent of the Company's 2005 capital budget, which will fund our drilling program and a 12 square kilometre 3-D seismic program before spring break-up. The Keg River light oil play at Red Earth will be Tempest's primary focus in 2005, and will include a planned 2-3 net wells late in the summer.

OTTER

Tempest's Banff natural gas play at the 100 percent working interest Otter property originated as a farm-in. Construction of a 100 percent-owned, 44 kilometre pipeline before spring break-up in 2004 enabled Tempest to tie-in six wells from the pool to the Red Earth natural gas plant. Production peaked at 5 mmcf per day in early 2004 and was at 3.7 mmcf per day at year-end. Some transient water issues occurred in late 2004 that negatively impacted the property. Currently we are monitoring the performance of the Otter wells to determine at what rates production will stabilize in these wells.

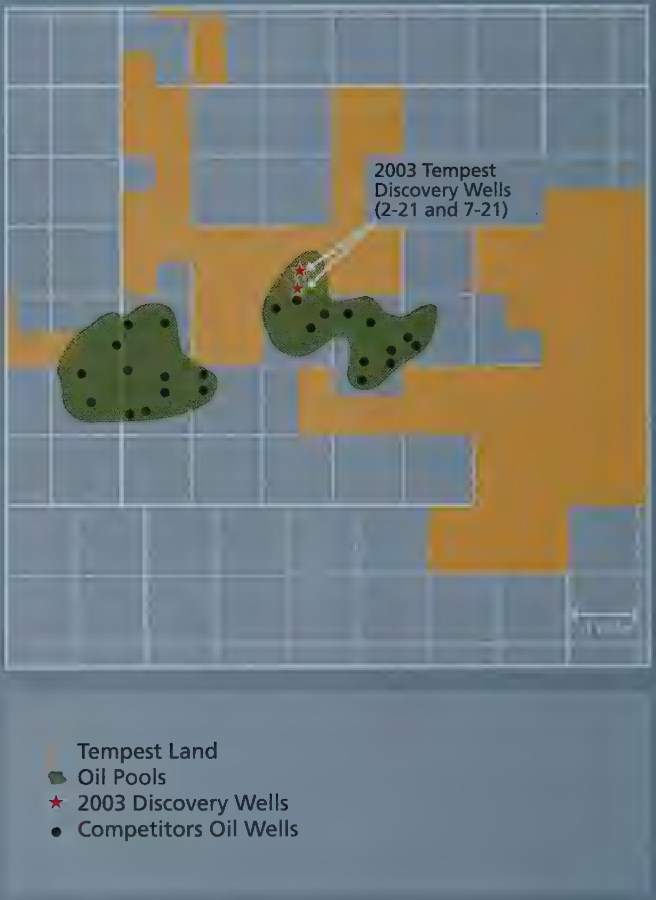
Otter lies in the midst of a prospective exploration fairway, generating optimism about finding further accumulations of natural gas through renewed, grassroots exploration. Tempest's gathering system and 12 sections of undeveloped land will facilitate capital-efficient exploration. With Tempest's current Northern Area focus concentrated on the Red Earth Keg River light oil play, further drilling in the greater Otter area has been deferred. However, the play area retains strong potential for additional natural gas exploration and development.

Red Earth Light Oil



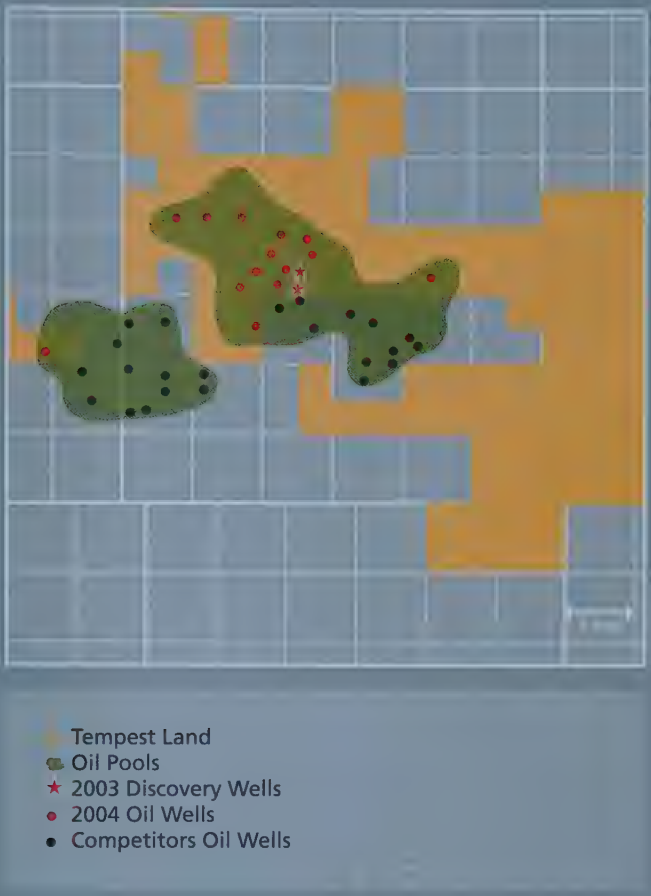
2002

- Tempest posted and purchased four sections of Crown land in March 2002.
- Tempest's in-house exploration team completed its evaluation and geological interpretation of 3-D seismic that was shot by another company in 1993-1994. The seismic indicated that there was an apparent structural low between and offsetting the two pools.
- New processing and interpretation techniques suggested the seismic low was caused by near-surface low velocity sediments and in reality could be a structurally high area, very prospective for oil.



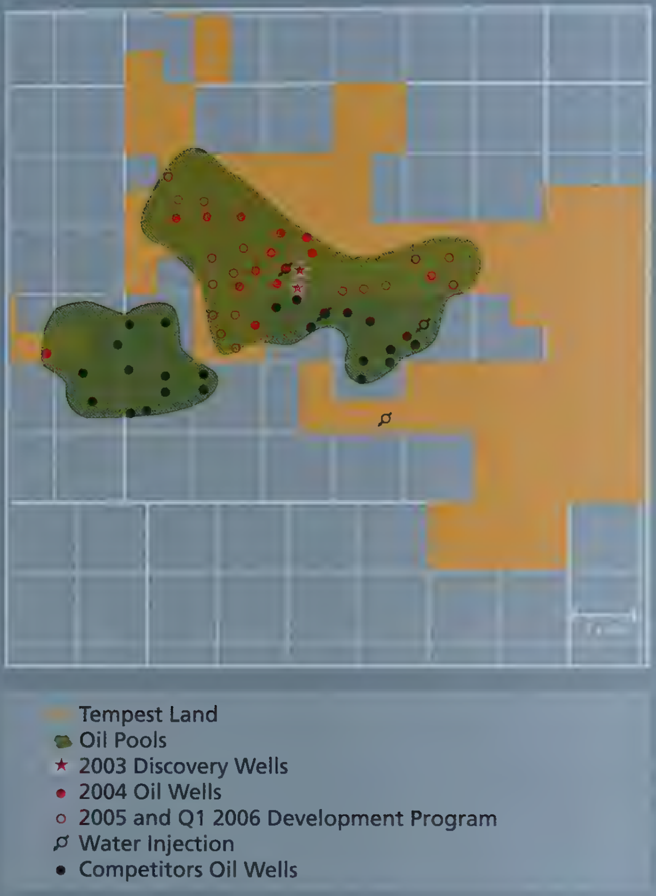
2003

- Tempest drilled the 2-21 oil discovery in February 2003. The discovery proved that Tempest's geological interpretation of a structural high between and offsetting the two pools was correct.
- The Company drilled the 7-21 step-out well in October 2003.



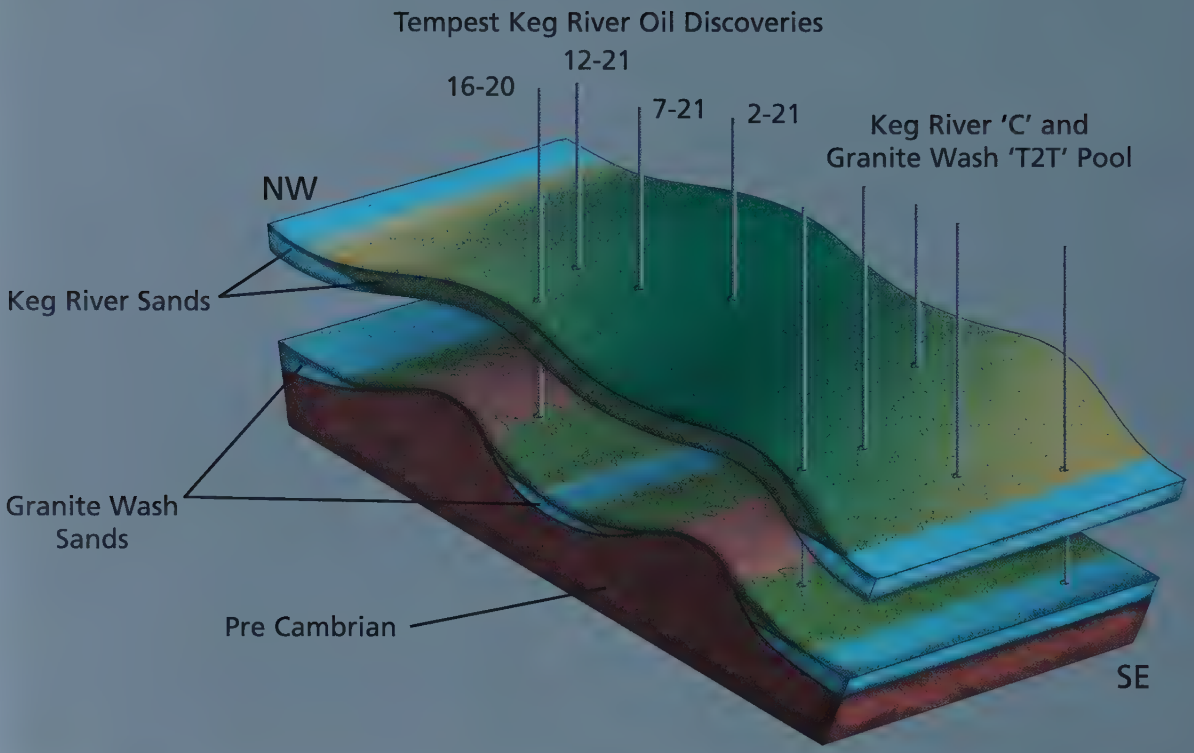
2004

- Tempest drilled 14 successful oil wells which further confirmed the pool extension. The wells also proved that the Keg River sand is extensive and continuous. Results showed a large plateau area that is oil bearing.
- Some of the development wells had lower pressure, indicating they were connected to the original discovery pool. Evaluation of the wells identified the need for waterflood for pressure maintenance.
- Tempest's successful drilling extended the play over multiple sections of 100 percent Company-owned land.
- Tempest shot new 3-D seismic in 2004, bringing the total coverage to over 90 square kilometres.



2005/Q1 2006

- Planning a 17-well development step-out program.
- Testing for significant further extension of light oil play.
- Implementation of waterflood.


Tempest Keg River Oil Discoveries
16-20
12-21
7-21
2-21
Keg River 'C' and Granite Wash 'T2T' Pool
NW
Keg River Sands
Granite Wash Sands
Pre Cambrian
SE

RED EARTH

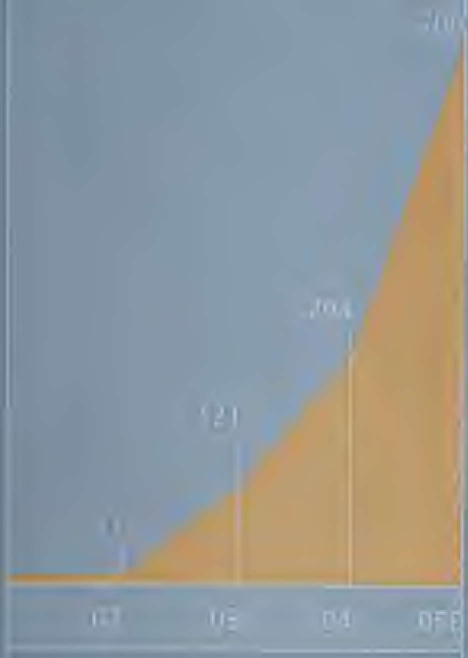
Tempest's exploration and development of the Keg River/ Granite Wash play at Red Earth is adding production of high quality, long-life light oil with potential to increase Tempest's corporate reserve life index. The 40 degree API oil produced at Red Earth generated netbacks averaging $33.55 per bbl in 2004. Net production following the 2004-2005 winter drilling season is estimated at 1,000 boe per day at the end of the first quarter. This will result in average production for the year of 700 boe per day.

Development history – Tempest and its partner have proceeded methodically in this seasonal access area. Following steady land accumulation beginning in 2002, the partners in 2003 drilled the 2-21 discovery well and the 7-21 outpost well that confirmed a significant extension of the Keg River 'C' pool. Tempest has a 50-100 percent working interest in the pool extension. In winter 2003-2004 Tempest and its partner drilled eight development wells that increased average production for the year to almost 600 bbls per day gross. On-stream costs at Red Earth average approximately $1.2 million per well, providing attractive economics on a flowing boe basis of $16,300.

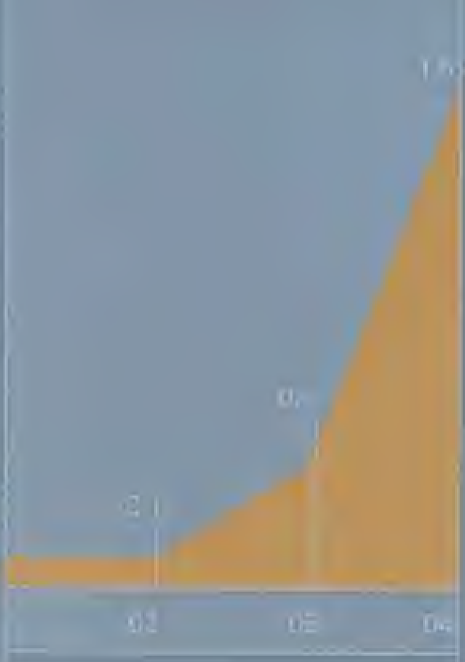
2004-2005 winter program – Tempest's in-house reinterpretation of 3-D seismic suggested strong oil prospectivity throughout the undeveloped area. The reinterpretation enabled Tempest to step out dramatically from the original pool extension. The 2004-2005 winter round of exploration and development drilling aimed to extend the Keg River's boundaries to the north, west and east, where Tempest's lands are held at 100 percent working interest.

At the time of printing this annual report, Tempest has drilled 12 wells in the 2004-2005 winter season, eight of which are on production at an average net rate of 90 boe per day each. The remaining wells will be on production shortly.

Resource potential – Tempest is optimistic about the Keg River's potential for significant volumes and long reserve life. The 2-21 discovery well, brought on production in mid-2003 at 210 bbls per day gross, has produced a cumulative 100,000 barrels. The 7-21 outpost well has produced at approximately 100 bbls per day since coming on-production in early 2003.



RED EARTH LIGHT OIL PRODUCTION (NET BBLS/DAY)



RED EARTH LIGHT OIL RESERVES (P+P) (MMBOE)

Results to date suggest a significant part of the area is oil-charged. The offsetting pools to the west and east have yielded cumulative production of approximately 4 million barrels over 40 years and 2 million barrels over 11 years, respectively. Despite this maturity, each pool continues to yield new drilling opportunities. With an apparent average 2-4 million barrels of oil-in-place per section of land, Tempest currently sees combined resource potential of 20-30 million barrels in the greater Keg River pool system. At year-end 2004, Tempest's independent reserve evaluator assigned 1.6 million boe in proved plus probable reserves to the Company's interests in the Keg River play area.

Reservoir management – The Keg River is a series of six sands at approximately 1,500 metres depth. Drilling to date has encountered variable pressures, suggesting portions of the reservoir may be in communication with the offsetting wells. Achieving sustained economic production will demand sustained reservoir engineering, including pressure maintenance. Tempest is formulating plans for a potential waterflood in the new pool area to maximize oil recovery over the long term.

Future potential – Tempest intends to systematically explore the Keg River potential on its extensive, 100 percent working interest lands to the northwest, north and northeast of the original pool extension. 3-D seismic coverage has been increased to a full township, or 36 net sections. The Company has 20 drilling locations in inventory, ranging from low-risk infill development to exploration opportunities in four new areas that would further extend the pool area. This inventory will be high-graded and drilled at a steady, prudent rate, with a balance of exploration and development wells in each winter season. Nearby infrastructure will enable expeditious tie-in of new production.

Emerging West 5 Exploration Area

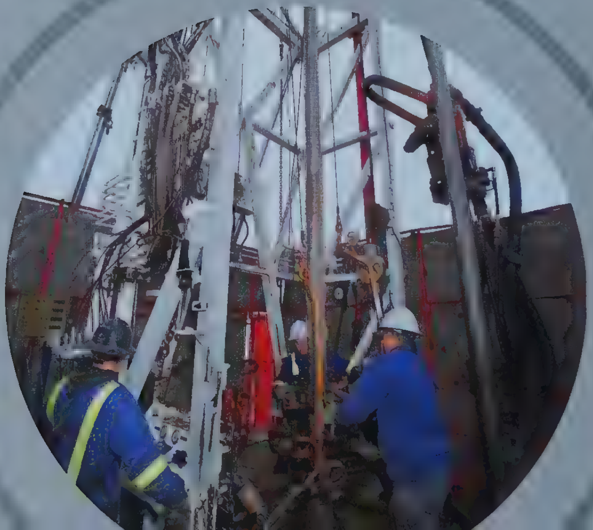
At Cygnet, Tempest is pursuing a multi-zone Cretaceous play, targeting both the gas-saturated Deep Basin type sediments and conventional shallower zones. A 100 percent exploration well drilled in early 2004 encountered Edmonton gas. Edmonton formation pools in this area are gas-saturated and free of water. The successful well was cased and shut-in. Tie-in of this well, which is somewhat remote from existing infrastructure, requires that Tempest first prove up additional reserves in the vicinity.

In January 2005 Tempest spudded its second exploration well at Cygnet, located to intersect several prospective Cretaceous sand zones. The well encountered four separate potential zones and was testing as of mid-March. This is a high-impact test with reserves potential of 10-15 bcf. If successful, both Tempest discoveries at Cygnet could be tied-in and brought on production before year-end. This year's well could generate numerous follow-up locations on Tempest's 17 sections of high working interest undeveloped lands.

At Edson, Tempest is working to build its land base beyond its current two-section foothold by pursuing farm-ins and possible acquisitions. Throughout 2005 Tempest will continue efforts to augment its land position.

West 5 Emerging Exploration Area

Over the past two years Tempest has worked to develop new plays that offer potential to mature into a third core area. Tempest's technical team has considerable previous experience in the medium-depth to deeper, higher-impact natural gas plays of Alberta's W5-W6 corridors. This is where the Company is undertaking exploration that, if successful, could establish a third core area. Tempest has gained several strategic footholds of prospective lands by participating in a series of Crown sales and farm-ins.



UNDEVELOPED LAND

As an exploration-driven company, Tempest continuously focuses on generating new opportunities. Continuous growth in the undeveloped land base is key to success. Tempest's land strategy is primarily prospect-driven, with limited land purchases made on-trend or for competitive reasons. Lands are acquired through Crown sales (frequently posted by Tempest), through freehold leasing and through farm-ins on a drill-to-earn basis. The Company seeks high working interests and large contiguous blocks. Tempest frequently employs brokers in order to keep details of land purchases confidential for competitive reasons.

In 2004 Tempest's land budget totalled $5.4 million, or 10 percent of overall capital expenditures. Central Alberta accounted for the majority of funds spent on land in 2004. At year-end 2004, Tempest's land base was 206,049 net undeveloped acres with an average working interest of 87 percent, a 23 percent increase in net acres from year-end 2003. An independent evaluation at December 31, 2004 valued these lands at $22.1 million.

In 2005 Tempest will continue to build its base of undeveloped land, with a similar ratio of capital spending assigned to land purchases.

LAND HOLDINGS	2004			2003		
(Acres)	Gross	Net	W.I.%	Gross	Net	W.I.%
Developed	**42,342**	**37,768**	**89**	26,930	22,337	83
Undeveloped	**236,715**	**206,049**	**87**	199,746	167,716	84
Total	**279,057**	**243,817**	**87**	226,676	190,053	84

NET UNDEVELOPED LAND BY AREA	2004		2003	
(Acres)	Gross	Net	Gross	Net
Northern	**104,880**	**74,969**	99,920	68,965
Central	**121,501**	**121,002**	92,224	91,661
Other	**10,334**	**10,078**	7,602	7,090
Total	**236,715**	**206,049**	199,746	167,716

DRILLING ACTIVITY

Tempest drilled 39 (32.8 net) wells in 2004, in line with the 40-60 wells forecast. For 2005 Tempest expects to drill 40-60 wells.

DRILLING ACTIVITY	2004			2003		
(Number of wells)	Gross	Net	W.I.%	Gross	Net	W.I.%
Oil	**15**	**9.5**	**63**	13	10.8	83
Natural gas	**18**	**17.9**	**99**	20	19.4	97
Dry/service	**6**	**5.4**	**90**	8	8.0	99
Total	**39**	**32.8**	**87**	41	38.2	93
Exploration	**27**	**26.3**	**97**	29	26.8	93
Development	**12**	**6.5**	**54**	12	11.3	95
Total	**39**	**32.8**	**87**	41	38.2	93
Success rate (%)	**85**	**92.0**	**–**	81	79.2	–

PRODUCTION AND RESERVES

Tempest's production averaged 3,634 boe per day in 2004, an increase of 35 percent from the 2003 average of 2,699 boe per day. Volume growth was achieved through exploratory and development drilling on internally-generated prospects. Average volumes consisted of 13.5 mmcf per day of natural gas and 1,388 barrels per day of crude oil and NGLs, for an average natural gas weighting of 62 percent, compared to 32 percent in 2003.

One hundred percent of Tempest's reserves as at December 31, 2004 were independently evaluated by Gilbert Laustsen Jung Associates (GLJ), independent reservoir engineers, according to the requirements of National Instrument (NI) 51-101. The following summary presentation and discussion conform in all material respects to the results of GLJ's evaluations.

Tempest increased its base of net proved and probable reserves in 2004. Tempest's discoveries and pool extensions added 2.5 million boe of proved plus probable reserves, replacing 2004 production by 1.9 times.

Before accounting for the year's production, Tempest's year-end proved reserves were up by 64 percent and proved plus probable reserves were higher by 41 percent over 2003 reserves.

Reserves Category	2004	% of Total	2003	% of Total	Year-Over-Year % Change
Proved producing	**4,519**	**61**	2,568	41	76
Proved developed non-producing	**765**	**10**	1,369	22	(44)
Proved undeveloped	**514**	**7**	410	7	25
Total proved	**5,798**	**78**	4,347	70	**33**
Probable	**1,641**	**22**	1,851	30	(11)
Total proved plus probable reserves	**7,439**	**100**	6,198	100	**20**

SUMMARY OF OIL AND GAS RESERVES (forecast prices and costs)

	Light/Medium Oil		Natural Gas		Total	
Reserves Category	Gross (mbbls)	Net (mbbls)	Gross (mmcf)	Net (mmcf)	Gross (mboe)	Net (mboe)
Proved						
Developed producing	2,320	1,965	13,190	10,262	4,519	3,675
Developed non-producing	494	372	1,627	1,253	765	581
Undeveloped	424	334	541	450	514	409
Total proved	3,239	2,671	15,356	11,965	5,798	4,665
Probable	865	710	4,658	3,686	1,641	1,324
Total proved plus probable	4,104	3,381	20,014	15,651	7,439	5,989

Note: Gross represents Company working interest before royalties. Net represents Company working interest after royalties.

NET PRESENT VALUES OF FUTURE NET REVENUE (forecast prices and costs)

($ millions)	Before Income Taxes Discounted At (%/yr)					After Income Taxes Discounted At (%/yr)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
Proved										
Developed	83.6	74.5	67.5	61.9	57.3	70.8	62.6	56.3	51.4	47.4
Developed non-producing	16.8	14.7	13.1	11.9	10.8	11.4	9.7	8.3	7.2	6.5
Undeveloped	6.4	4.6	3.5	2.6	1.9	4.4	3.0	2.2	1.6	1.1
Total proved	106.8	93.9	84.0	76.3	70.1	86.6	75.3	66.8	60.2	55.0
Probable	28.7	21.5	16.9	13.7	11.3	20.2	14.7	11.3	8.9	7.2
Total proved plus probable	135.5	115.4	100.9	90.0	81.4	106.8	90.0	78.1	69.1	62.2

TOTAL FUTURE NET REVENUE (undiscounted) (forecast prices and costs)

Reserves Category ($ millions)	Royalties	Operating Costs	Dev. Costs	Well Aband. Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved reserves	37.7	70.1	7.8	2.2	106.8	20.2	86.6
Proved plus probable reserves	48.8	90.5	10.9	2.4	135.4	28.7	106.8

SUMMARY OF PRICING AND EXCHANGE RATE ASSUMPTIONS (forecast prices and costs)

Year	WTI Cushing (Oklahoma) (US$/bbl)	Edmonton Par Price 40° API (Cdn$/bbl)	Hardisty Heavy 12° API (Cdn$/bbl)	Cromer Medium 29.3° API (Cdn$/bbl)	Natural Gas AECO Gas Price (Cdn$/GJ)	Exchange Rate (US$/Cdn$)
Historical						
2003	31.07	43.66	26.26	37.55	6.32	0.721
2004	41.38	52.96	29.11	45.75	6.53	0.769
Forecast						
2005	42.00	50.25	27.50	43.75	6.27	0.820
2006	40.00	47.75	28.50	41.50	6.03	0.820
2007	38.00	45.50	28.75	39.50	5.84	0.820
2008	36.00	43.25	27.25	37.75	5.70	0.820
2009	34.00	40.75	25.50	35.50	5.70	0.820
2010	33.00	39.50	24.75	34.25	5.70	0.820
2011	33.00	39.50	24.75	34.25	5.70	0.820
2012	33.00	39.50	24.75	34.25	5.70	0.820
2013	33.50	40.00	24.75	34.75	5.79	0.820
2014	34.00	40.75	25.50	35.50	5.89	0.820
2015	34.50	41.25	25.75	36.00	5.98	0.820
2016	35.19	42.08	26.27	36.72	6.10	0.820
2017	35.89	42.92	26.79	37.45	6.22	0.820
2018	36.61	43.77	27.33	38.20	6.35	0.820
2019	37.34	44.65	27.87	38.97	6.48	0.820

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE (forecast prices and costs)

	Light/Medium Oil			Associated and Non-Associated Gas			Total		
Factors	Proved (mbbls)	Probable (mbbls)	Proved Plus Probable (mbbls)	Proved (mmcf)	Probable (mmcf)	Proved Plus Probable (mmcf)	Proved (mboe)	Probable (mboe)	Proved Plus Probable (mboe)
December 31, 2003	2,341.3	740.2	3,082.3	12,043.2	6,819.5	18,862.7	4,348.5	1,876.8	6,226.1
Discoveries and extensions	1,056.5	283.5	1,340.0	4,262.6	1,358.0	5,620.6	1,767.0	509.8	2,276.8
Acquisitions	–	–	–	775.9	110.1	886.0	129.3	18.4	147.7
Dispositions	–	–	–	–	–	–	–	–	–
Production	508	–	508.0	4,931.2	–	4,931.2	1,329.9	–	1,329.9
Technical revisions	349.3	(159.4)	189.9	3,205.6	(3,628.6)	(423.0)	883.6	(764.2)	119.4
December 31, 2004	3,239.1	864.3	4,104.2	15,356.1	4,659.0	20,015.1	5,798.5	1,640.8	7,440.1

Note: No heavy oil.

SUMMARY OF OIL AND GAS RESERVES (constant prices and costs)

	Light/Medium Oil		Natural Gas		Total	
Reserves Category	Gross (mbbls)	Net (mbbls)	Gross (mmcf)	Net (mmcf)	Gross (mboe)	Net (mboe)
Proved						
Developed producing	2,461	2,119	13,255	10,318	4,670	3,839
Developed non-producing	494	369	1,627	1,253	765	578
Undeveloped	424	342	541	450	514	417
Total proved	3,379	2,830	15,423	12,021	5,949	4,834
Probable	883	727	4,671	3,696	1,662	1,343
Total proved plus probable	4,262	3,557	20,094	15,717	7,611	6,176

Note: No heavy oil or natural gas liquids.

NET PRESENT VALUES OF FUTURE NET REVENUE (constant prices and costs)

($ millions)	Before Income Taxes Discounted At (%/yr)					After Income Taxes Discounted At (%/yr)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
Proved										
Developed	84.4	74.4	66.7	60.8	55.9	72.1	63.0	56.2	50.9	46.7
Developed non-producing	18.2	15.7	13.8	12.3	11.2	9.7	7.8	6.4	5.3	4.5
Undeveloped	6.1	4.4	3.2	2.3	1.7	6.5	5.2	4.3	3.6	3.1
Total proved	108.7	94.4	83.7	75.4	68.8	88.4	76.0	66.8	59.8	54.3
Probable	33.1	24.5	19.0	15.3	12.6	22.9	16.5	12.6	9.9	8.1
Total proved plus probable	141.8	118.9	102.7	90.7	81.4	111.2	92.5	79.4	69.8	62.3

TOTAL FUTURE NET REVENUE UNDISCOUNTED (constant prices and costs)

Reserves Category ($ millions)	Royalties	Operating Costs	Dev. Costs	Well Aband. Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved reserves	36.0	68.9	7.9	1.9	108.7	20.4	88.4
Proved plus probable reserves	47.5	86.2	11.0	2.0	141.8	30.6	111.2

SUMMARY OF PRICING ASSUMPTIONS (constant prices and costs)

Year	WTI Cushing (Oklahoma) (US$/bbl)	Edmonton Par Price 40° API (Cdn$/bbl)	Hardisty Heavy 12° API (Cdn$/bbl)	Cromer Medium 29.3° API (Cdn$/bbl)	Natural Gas AECO Gas Price (Cdn$/GJ)	Exchange Rate (US$/Cdn$)
Historical (year-end)						
2000	30.22	44.56	32.61	39.91	5.08	0.6740
2001	25.97	39.40	23.48	31.56	6.21	0.6448
2002	26.08	40.33	30.60	35.48	4.04	0.6376
2003	31.07	43.66	31.18	37.55	6.66	0.7213
2004 (year-end)	41.38	52.96	35.64	45.75	6.88	0.7734

CAPITAL EXPENDITURES

($000s)	**2004**	%	Inception to Date	%
Land and lease	**5,374**	**11**	20,404	13
Seismic	**2,828**	**6**	9,398	6
Drilling and completions	**20,956**	**41**	70,493	46
Property acquisitions	**6,000**	**12**	10,716	7
Property dispositions	**–**	**–**	–	–
Finding costs	**35,158**	**70**	111,011	72
Facilities	**15,804**	**30**	40,698	28
Corporate assets	**–**	**–**	691	–
Finding and development costs spent	**50,962**	**100**	152,400	100
Acquisition tax accrual	**–**	**–**	2,397	–
Finding and development costs	**50,962**	**100**	154,797	100

FINDING AND DEVELOPMENT COSTS

	Capital Expenditures ($000s)	Proved Reserve Additions (mboe)	Proved Costs ($/boe)	Proved Plus Probable Reserve Additions (mboe)	Proved Plus Probable Costs ($/boe)	Inception to Date Average Proved Plus Probable* ($/boe)
Drilling costs on exploration and development program	20,956	2,779	7.54	2,544	8.24	7.31
Finding costs on exploration and development program before 2004 revisions	35,158	2,779	12.65	2,544	13.82	11.51
F&D exploration and development program after 2004 revisions (a)	50,962	2,779	18.34	2,544	20.03	15.80
Change in proved future development capital (b) (1)	(4,016)	n/a	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c) (1)	(1,884)	n/a	n/a	n/a	n/a	n/a
Proved F&D including change in proved future development capital (d) = (a)+(b)	46,946	2,779	**16.89**	n/a	n/a	16.61
Proved plus probable F&D including change in proved future development capital (e) = (a)+(c)	49,078	n/a	n/a	2,544	**19.29**	16.93

* Includes established basis for 2001 and 2002.

(1) Change in future development capital.

($000s)	Proved	Change	Proved Plus Probable	Change
2004	7,823		10,925	
		(4,016)		(1,884)
2003	11,839		12,809	

The following cautionary statements need to be considered when evaluating finding and development costs: first, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in future development costs generally will not reflect total finding and development costs related to reserve additions for that year; and second, the term boe may be misleading. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

RESERVE LIFE INDEX	
Production (mboe)	1,329,906
Proved reserves (mboe)	5,798,500
Proved reserve life index (years)	4.4
Proved plus probable reserves (mboe)	7,440,100
Proved plus probable reserve life index (years)	5.6

RECYCLE RATIO

The recycle ratio is a measure for evaluating the effectiveness of a Company's reinvestment program. The ratio measures how well the Company replaced every boe of production. The chart below depicts that Tempest received a net $21.65 per boe it sold and it cost $16.89 to find a replacement boe.

(6:1)	2004
Operating netback ($/boe)	21.65
Proved finding and development costs ($/boe)	16.89
Proved reinvestment efficiency ratio	1.3
Proved plus probable finding and development costs ($/boe)	19.29
Proved plus probable reinvestment efficiency ratio	1.1

RESERVES REPLACEMENT	**2004**	**2003**
Oil (bbls)	**508,046**	674,648
Natural gas (mcf)	**4,931,158**	2,537,032
Equivalent barrels (boe)	**1,329,906**	985,045
Reserve additions	**2,544,000**	3,382,000
Reserves replacement	**1.9**	3.4
Oil (bbls/day)	**1,388**	1,848
Natural gas (mcf/day)	**13,473**	5,102
Equivalent barrels (boe/day)	**3,634**	2,699

NET ASSET VALUE

Tempest presents one method for calculating net asset value below. This calculation is presented for December 31, and incorporates estimates that may not be comparable year-over-year and are only at a point in time. An independent evaluation was performed for land and reserves for both years. The reader is cautioned that the presentation does not reflect all aspects of the Company and that reserve definitions changed after 2002 (see MD&A discussion regarding new accounting and regulatory requirements).

($000s)	**2004**	2003
Present value of reserves (p+p discounted at 10%)	**100,912**	62,821
Undeveloped acreage	**22,139**	15,869
Working capital deficiency	**(32,167)**	(20,859)
Option proceeds	**5,533**	7,161
Tax pools at 10%	**5,560**	4,820
Estimated value	**101,977**	69,812
Diluted shares	**21,537**	20,564
Per diluted share	**4.74**	3.40

Diluted shares includes all outstanding Class A shares as well as assuming the full conversion of the Class B shares at the year-end closing price for Tempest's Class A shares (2004 – $6.69, 2003 – $5.85) and the exercise of all stock options.

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Tempest Energy Corp. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2004. The reserves data consist of the following:
   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004, using forecast prices and costs; and
   (ii) the related estimated future net revenue; and
   (b) (i) proved oil and gas reserves estimated as at December 31, 2004, using constant prices and costs; and
   (ii) the related estimated future net revenue.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).
3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2004, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $M)			
		Audited	Evaluated	Reviewed	Total
February 11, 2005	Canada	$ –	$100,912	$ –	$100,912

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
6. We have no responsibility to update this evaluation for events and circumstances occurring after the preparation dates.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GILBERT LAUSTSEN JUNG ASSOCIATES LTD.

Dana B. Laustsen, P. Eng.
Gilbert Laustsen Jung Associates Ltd.

Calgary, Alberta, Canada
Dated February 26, 2005

The following discussion and analysis is a review of operations, current financial position and outlook for the Company and should be read in conjunction with the audited consolidated financial statements and related notes. This discussion reflects the combined totals of Tempest Energy Corp. and its wholly-owned subsidiaries 951554 Alberta Ltd. and Point Bar Petroleums Ltd. as well as their combined Partnership arrangement, the Tempest Energy Production Partnership which collectively are referred to as "Tempest" or the "Company".

The terms "cash flow from operations", "cash flow", "cash flow per share" and "debt-to-cash-flow ratio" in this discussion are not recognized measures under Canadian generally accepted accounting principles (GAAP). Management believes that in addition to net earnings, cash flow is a useful supplemental measure as it provides an indication of the results generated by the Company's principal business activities before the consideration of how those activities are financed or how the results are taxed. Investors are cautioned, however, that this measure should not be construed as an alternative to net earnings determined in accordance with GAAP, as an indication of Tempest's performance.

Tempest's method of calculating cash flow may differ from other companies, and accordingly it may not be comparable to measures used by other companies. Tempest calculates cash flow from operations as "funds from operations" before the change in non-cash working capital related to operating activities. In addition, the terms "cash flow" and "funds from" are used interchangeably. The consolidated statements of cash flows in the audited consolidated financial statements present the reconciliation between earnings and cash flow. All boe numbers are calculated converting natural gas mcf to boe at 6:1.

FORWARD-LOOKING STATEMENTS

Statements in this document may contain forward-looking information. Estimates provided for 2005 and beyond are based on assumptions of future events and actual results could vary significantly from these estimates. The reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect. Events or circumstances may cause actual results to differ materially from those predicted as a result of numerous known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Company. The reader is cautioned not to place undue reliance on this forward-looking information. Additional information relating to Tempest, including the Annual Information Form (AIF) is available at www.sedar.com or the Company's website at www.tempestenergy.com.

SIGNIFICANT FINANCIAL EVENTS

- Production, revenue and cash flow were higher in 2004 by 35 percent, 65 percent and 77 percent, respectively.
- Tempest raised $10.0 million on December 13, 2004, issuing 1,162,791 Class A shares at a price of $8.60 per Class A share, on a flow-through basis.
- Tempest has hedged 5,000 gigajoules (GJ) per day of natural gas, using a three-way structure, for the period August 2004-July 2005. This hedge is based on the AECO benchmark price in Canadian dollars and includes the purchase of a $6.21 per GJ put (floor), the sale of a $7.00 per GJ call and the purchase of an $8.68 per GJ call.
- Tempest syndicated its banking facilities to the CIBC and the National Bank to establish a $40.0 million bank line.

FINANCIAL AND OPERATING SUMMARY

	Fourth Quarter Ended December 31			Twelve Months Ended December 31			Full Year	
	2004 (000s)	2003 (000s)	% Change	**2004 (000s)**	2003 (000s)	% Change	**2004 (per boe)***	2003 (per boe)*
Oil revenue	**5,985**	4,520	32	**23,438**	23,995	(2)	**46.13**	33.57
Oil hedging	**–**	(560)	(100)	**–**	(2,318)	(100)	**–**	(3.44)
Natural gas revenue	**8,581**	3,327	158	**31,852**	11,796	170	**38.76**	37.97
Natural gas hedging	**13**	–	100	**74**	–	100	**0.09**	–
Oil and natural gas revenue	**14,579**	7,287	100	**55,363**	33,473	65	**41.63**	33.98
Royalties (net of ARTC)	**(2,536)**	(1,721)	47	**(11,942)**	(7,716)	55	**(8.98)**	(7.83)
Production expenses	**(4,507)**	(1,837)	145	**(10,475)**	(7,276)	44	**(7.88)**	(7.39)
Field netback	**7,535**	3,730	102	**32,946**	18,481	78	**24.77**	18.76
Interest expense	**(365)**	(79)	361	**(1,262)**	(384)	229	**(0.95)**	(0.39)
Interest income	**1**	1	(32)	**3**	12	(76)	**–**	0.01
G&A costs	**(1,063)**	(733)	45	**(3,823)**	(2,726)	38	**(2.87)**	(2.82)
G&A recoveries	**29**	51	(43)	**174**	186	(6)	**0.13**	0.19
G&A capitalized	**662**	(299)	(321)	**1,140**	825	38	**0.86**	0.84
Reclamation	**(260)**	–	(100)	**(260)**	–	100	**(0.20)**	–
Income tax expense	**(31)**	(30)	2	**(121)**	(120)	1	**(0.09)**	(0.12)
Cash flow from operations	**6,508**	2,641	146	**28,797**	16,275	77	**21.65**	16.52
Depletion, depreciation and accretion	**(5,956)**	(4,003)	49	**(20,531)**	(12,529)	64	**(15.44)**	(12.72)
Stock-based compensation	**(417)**	(482)	(14)	**(1,802)**	(1,851)	(3)	**(1.35)**	(1.88)
Earnings (loss) before income tax	**426**	(1,815)	(123)	**6,845**	2,015	240	**5.15**	2.04
Future income tax (expense) recovery	**136**	683	(80)	**(2,554)**	(928)	175	**(1.92)**	(0.94)
Net earnings (loss)	**531**	(1,162)	146	**4,171**	967	331	**3.14**	0.98

* Per boe @ 6:1.

OIL NETBACKS

Year ended December 31 ($/bbl)	**2004**	2003	2002
Sales price	**46.13**	33.57	32.80
Royalties	**9.04**	7.44	7.35
Production expenses	**10.81**	7.82	6.61
Netback	**26.27**	16.87	18.84
Royalty percentage	**20%**	23%	22%
Average daily production	**1,388**	1,848	1,475

NATURAL GAS NETBACKS

Year ended December 31 (boe 6:1)	2004	2003	2002
Sales price	**38.76**	37.97	23.90
Royalties	**10.29**	9.08	4.37
Production expenses	**4.44**	5.54	4.86
Netback	**24.02**	23.36	14.67
Royalty percentage	**27%**	24%	18%
Average daily production	**2,246**	851	429

2004 OVERVIEW AND 2005 GUIDANCE

Area	2005 Estimate (boe/day)	2004 Production (boe/day)	2004 % of Total Production	2003 Production (boe/day)	2004 Undeveloped Land (net acres)
Chipman oil	800	**1,094**	**30**	1,727	
Chipman gas	500	**465**	**15**	328	**39,178**
Fort Saskatchewan gas	800	**161**	**5**	2	**34,103**
Red Earth oil	700	**294**	**10**	121	
Red Earth gas	100	**180**	**5**	450	**48,814**
Otter gas	300	**642**	**17**	–	**3,695**
Norris gas	500	**109**	**3**	4	**14,941**
Looma/Joarcam gas	500	**606**	**17**	60	**5,581**
Other/Cygnet	300 – 800	**84**	**–**	7	**59,737**
Total	4,500 – 5,000	**3,634**	**100**	2,699	**206,049**

2004 Overview

In 2004 Tempest continued to execute its core strategies of exploration and development, with growth predominantly through the drill bit. At the outset of 2004, Tempest announced guidance for production (3,600 boe per day), cash flow ($25.0 million) and earnings before tax ($8.0 million). Actual results included production (3,634 boe per day), cash flow ($28.8 million or $1.56 per basic share) and earnings before tax ($6.8 million or $0.37 per basic share). Net income was negatively affected by higher than anticipated depletion charges and the adoption of stock-based compensation and fourth quarter results were negatively affected by water issues at Otter.

Tempest drilled 39 (32.8 net) wells in 2004, which resulted in 14 (8.5 net) oil wells, 15 (14.9 net) natural gas wells and 10 (9.4 net) dry and abandoned wells, for a success ratio of 74 percent. The drilling program shifted Tempest's production mix to 62 percent natural gas from 68 percent oil in 2003. As well Tempest added 38,333 net acres of undeveloped land during the year.

Central Area – The use of 3-D seismic in the Chipman area has been key to locating natural gas opportunities. The area produced more than two times the volume of natural gas in 2004 compared to 2003, resulting in natural gas equivalent production of 810 boe per day versus 401 boe per day in 2003. In Central Alberta, Tempest closed a $6.0 million property acquisition at mid-year which added production, some new facilities and over 20 sections of land at Bon Accord. As well, Tempest continued drilling development wells at Joarcam, which increased production to more than 17 percent of the 2004 corporate total.

Northern Core Area – From January to March 2004 Tempest tied in its Otter natural gas wells. This gas provided over $5 million or approximately 15 percent of total operating income to Tempest in 2004. On the oil side, the Company drilled eight (4.5 net) wells in the January to March 2004 time frame and an additional 12 (7.5 net) wells from December 2004 to March 2005. Production results in early 2004 were disappointing based on the information received while drilling the wells. However, the Company prepared a waterflood report in the summer of 2004 and subsequent drilling has confirmed that pressure maintenance could greatly enhance the value of the oil pool.

In order to maintain a strong balance sheet and have access to acquisition opportunities, Tempest completed an equity financing on December 13, 2004. The Company issued 1,162,791 Class A shares at $8.60 per share on a flow-through basis. Also, as part of risk management, Tempest hedged 5,000 GJs per day of natural gas to July 2005. To maintain a reasonable level of leverage the Company will access sources of financing, including entering the equity markets as required. The Company also has credit available through existing banking lines and will deploy capital as we encounter appropriate opportunities.

2005 Guidance

Annual forecasts for 2005 include average production (4,500-5,000 boe per day), cash flow ($35-$40 million or approximately $1.70-$1.90 per basic share), earnings ($7-$9 million) and capital expenditures ($40-$50 million).

2005 Year-to-Date Activities

Northern Alberta Core Area – Since drilling the initial Red Earth discovery in February 2003, Tempest has drilled 17 (10 net) delineation wells which have intersected Keg River oil pay. This included 12 (7.5 net) wells drilled from December 2004 to March 2005, which delineated the pool over eight sections of land and proved up a significant aerial extension to the Keg River pool. The new wells are now on-stream with initial production rates of 50-200 barrels of oil per day per well.

During break-up Tempest will evaluate strategies for the entire property including development and exploration drilling, seismic analysis and interpretation, as well as waterflood and facility options. An additional 15-20 development drilling locations have been identified on 3-D seismic, with over 10 sections of additional lands prospective from an exploration/extension point of view.

Production from this property is long life, 40° API oil which generates strong netbacks reflecting Edmonton par oil prices less $1.50 per barrel, with some wells receiving a royalty holiday. Tempest anticipates that the pool will average 600-800 barrels per day of light oil in 2005, and provide further growth in 2006 and beyond.

Northern Natural Gas – In December 2004, Tempest temporarily suspended natural gas production of about 800 boe per day to install water handling facilities at Otter. Otter production in the first quarter of 2005 is expected to average 300 boe per day, after internal compressor problems shut in more than 500 mcf per day for approximately one month.

Chipman Oil – The Chipman oil pools represent approximately 900 barrels per day of low decline production. Tempest now has five electric submersible pumps operating in the Chipman oil property. Based on their performance, the Company may install 2-4 additional pumps in 2005. As well, Tempest plans to drill an additional two horizontal infill wells during break-up to complete the delineation of these pools.

Chipman Natural Gas – Chipman gas represents approximately 13 percent of 2004 corporate production. As these properties decline, we expect that further drilling identified on the offsetting new 3-D at Norris will backfill the volumes. Tempest is considering a 10 kilometre pipeline to ATCO to eliminate production bottlenecks in the area. These facilities would cost approximately $3 million to build, with construction dependent on finding sufficient reserves at Norris.

Central Area Natural Gas – Looma/Joarcam represents 17 percent of 2004 production and will be a strong asset for many years, based in part on the property's coalbed methane (CBM) potential.

W5 Central Exploration – Tempest recently drilled a 100 percent working interest well in its emerging W5 multi-zone area. The well encountered two primary and two secondary zones. Results from completion operations will determine a development strategy for these potential reserves. The Company has over 15 sections of contiguous land in the area.

3-D Seismic Programs – Tempest has invested heavily in 3-D seismic for its exploration program, which covers a significant proportion of the Company's undeveloped acreage. There are four distinct parts to this investment:

- An 86.5 square kilometre 3-D seismic program west of Chipman in Central Alberta, which has now been completed;
- A 12 square kilometre 3-D program on 100 percent working interest lands on the northern edge of the Red Earth Keg River oil pool, now completed;
- A 113 square kilometre 3-D seismic program at Fort Saskatchewan/Redwater in the Central Area, which will be completed by mid-March; and
- A 13 square kilometre 3-D program over lands held at Redwater in Central Alberta, which will be completed by the end of March.

The data from these 3-D seismic programs will be interpreted during break-up leading to an extensive exploration drilling program.

Outlook

Tempest continues to focus strongly on exploration. However, based on our successes and related follow-up development activity, we expect to balance our exploration with development drilling efforts in 2005. We are engaged in extensive development drilling in the Northern Area in the first quarter which is expected to follow with exploration drilling on 3-D prospects in the Central Area in the third and fourth quarters.

PRODUCTION

	Quarter Ended December 31			Year Ended December 31		
	2004	2003	% Change	**2004**	2003	% Change
Production						
Oil (bbls/day)	**1,284**	1,384	(7)	**1,388**	1,848	(25)
Gas (mcf/day)	**14,694**	6,484	127	**13,473**	5,102	164
Total (boe/day)	**3,733**	2,464	52	**3,634**	2,699	35
Price						
Oil ($/bbl)	**50.67**	24.07	111	**46.13**	30.04	54
Gas ($/mcf)	**6.35**	5.17	23	**6.47**	6.18	5
Total ($/boe)	**42.45**	27.11	57	**41.63**	32.25	29
% oil	**34**	56		**38**	68	

Tempest's 2004 production rose 35 percent to an average 3,634 boe per day (38 percent oil) versus 2,699 boe per day (68 percent oil) in 2003. This equates to a 25 percent decrease in oil production and a 164 percent increase in natural gas production. The new natural gas production came mainly from Otter, Fort Saskatchewan and Joarcam.

In the fourth quarter of 2004, production was 52 percent higher at 3,733 boe per day compared to the same period in 2003, but was down from the 4,001 boe per day in the third quarter of 2004, mainly due to temporary difficulties with Tempest's production base at Otter.

The Central area continues to be a major focus for Tempest, contributing 2,509 boe per day or 69 percent of total corporate production. In 2003 flush oil production from the horizontal oil wells came off and 2004 depicted the more sustainable production profile that is characteristic of this type of well. The Central area provides year-round access for exploration and continued development. At year-end 2004, Tempest had more than 2.0 mmcf per day behind pipe and anticipates being active in the region in the third and fourth quarters of 2005. This will include drilling locations that are identified on 212 square kilometres of new 3-D seismic.

For 2004, the Northern area generated significant growth over 2003 with volumes of 1,115 boe per day versus the prior year's 571 boe per day. Oil accounted for 294 barrels per day in 2004 (2003 – 121 barrels per day), while gas was 4.9 mmcf per day (2003 – 2.7 mmcf per day). This represented a 143 percent and 81 percent growth respectively. Due to the success of the oil drilling, 2005 will be a transition year for the Northern Area as we shift production to long-life light oil.

OIL AND NATURAL GAS REVENUES

Revenues were up 65 percent in 2004 to $55.4 million compared to $33.5 million in 2003. The growth is mainly attributable to a 35 percent increase in production and a 23 percent increase in commodity prices. Increased natural gas prices contributed five percent to revenue growth whereas oil prices were up 54 percent from the previous year. In 2004, the Central area accounted for 69 percent (2003 – 75 percent) of total revenue. The significant oil price increase reflects the strength of the benchmark WTI crude oil price which gained 33.3 percent on a year-over-year basis to average US$41.44. This more than offset the nine percent increase in the Canadian/U.S. exchange rate which rose to 0.83 from 0.76 year-over-year.

In the fourth quarter of 2004, revenues from crude oil and natural gas increased 100 percent to $14.6 million, compared to $7.3 million for the fourth quarter of 2003. The increase was due to a 52 percent production volume increase and a 57 percent increase in the realized selling price. Although oil production was 25 percent lower, natural gas was 165 percent higher year-over-year.

For 2005 Tempest anticipates a 25 percent increase in revenues, based on the strength of oil and natural gas prices and no change in the value of the Canadian dollar over 2004.

FINANCIAL INSTRUMENTS (HEDGING)

Tempest realized a $73,494 gain (2003 – $2,318,114 loss) on hedging in 2004 based on 5,000 GJs from July to December on a floor price of $6.21 per GJ, the sale of a $7.00 per GJ call and the purchase of an $8.68 per GJ call (2003 – 800 barrels of oil per day at $25.40 WTI). The gas hedge is in place until July 2005 and at December 31, 2004 Tempest had an unrealized mark-to-market gain of $395,166.

Management considers hedging a valuable tool to offset the risk related to leveraged capital. Tempest will hedge periodically when price volatility would put its capital program or internal debt guidelines at risk. Following new accounting guidelines, Tempest has documented the gas hedge and has demonstrated its effectiveness. Hedge accounting would be discontinued for any hedging relationships that no longer meet the requirements of the guideline and mark-to-market with income statement impacts would be required.

ROYALTIES

Royalty costs as a percentage of sales are trending down as maturing wells with lower production receive a lower royalty rate. As well, the average royalty rate reflects a royalty holiday on a portion of Tempest's Northern oil production. Royalty costs were $11.9 million, or $8.98 per boe, compared to $7.7 million, or $7.83 per boe in 2003. Royalty charges were 22 percent of revenue in 2004 compared to 23 percent in 2003. After deducting $500,000 in Alberta Royalty Tax Credits, the Company had net revenue of $43.4 million in 2004, an increase of 69 percent from 2003's net revenue of $25.8 million.

In the fourth quarter royalty costs were $2.5 million or $7.39 per boe, compared to $1.8 million or $7.59 per boe in the fourth quarter of 2003. Fourth quarter royalties of 17 percent of sales reflect a royalty holiday status on some Red Earth oil production late in the year.

Tempest's core properties were developed through exploration and are therefore eligible for Alberta Royalty Tax Credits ("ARTC"). Based on current commodity prices ARTC is set at 25 percent of Crown royalties paid to a maximum of $500,000, which was achieved in both 2004 and 2003. ARTC is maximized early in the year so first quarter net royalty rates are below those incurred for the balance of the year when ARTC is no longer available. Royalty rates for 2004 were as anticipated and Tempest expects that the corporate royalty rate will remain in the 20-25 percent range for 2005.

($000s)	**2004**	2003	% Change
Oil	**4,813**	5,475	(12)
Gas	**7,629**	2,741	178
ARTC	**(500)**	(500)	–
Total	**11,942**	7,716	55
Per boe ($)	**8.98**	7.83	15
% of sales	**22%**	23%	(4)

TRANSPORTATION COSTS

During the year Tempest separated out transportation costs on its income statement to provide a gross sales number. Transportation costs per unit of production averaged $1.41 per boe in 2004, compared to $1.73 per boe in 2003. The decrease is reflective of the Company's production becoming more gas weighted and the ownership of facilities in our Northern Area. As well, the decrease on a boe basis reflects the stabilized oil production at Chipman where emulsion hauling has decreased. In the fourth quarter of 2004 these costs declined to $1.22 per boe (Q4, 2003 – $1.75). We anticipate transportation costs will be approximately $2.00 per boe in 2005, as a larger portion of gas volumes are derived from our Central Area where more third-party transportation is utilized.

	2004	2003	% Change
Expenses ($000s)	**1,869**	1,702	10
Per boe ($)	**1.41**	1.73	(18)

OPERATING EXPENSES

Operating costs per unit of production averaged $6.47 per boe in 2004, compared to $5.66 per boe in 2003. The $8.6 million in operating costs (2003 – $5.6 million) resulted in operating income of $32.9 million (2003 – $18.5 million). Tempest had anticipated operating costs closer to $4.50 per boe in 2004; however, rising operating costs reflect the higher cost of supplies and field services due to drilling activity. The Company rented seven compressors in 2004 to accommodate our increased emphasis on shallow gas wells in Central Alberta.

In the fourth quarter of 2004 operating costs were anomalous at $11.90 per boe (Q4, 2003 – $6.35) reflecting lower production, issues at Otter, service provider shortages as well as additional costs associated with colder weather operations. Tempest benefits from its investment in infrastructure; we have lower operating costs than our peers on a unit basis. We anticipate operating costs will be $5.50-$6.50 per boe in 2005 as higher volumes offset further cost increases.

	2004	2003	% Change
Expenses ($000s)	**8,606**	5,573	54
Per boe ($)	**6.47**	5.66	14

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses ("G&A") for 2004 were $1.89 per boe versus $1.74 in 2003. The net $2.5 million (2003 – $1.7 million) was after overhead recoveries and capitalization. Management had expected 2004 G&A to remain flat on a boe basis as volume increases offset gross G&A cost increases. The year-over-year increase reflects bonuses paid in January 2004. The bonuses amounted to $450,000 compared to $40,000 in 2003. As well, fees associated with the bank syndication and higher levels of debt were $249,387 compared to $47,813 in bank fees in 2003. Finally, reserve report costs were significantly higher due to NI 51-101 and our mid-year reserves update, totaling $163,925, compared to $31,843 in the prior year.

Salaries and office rent comprised approximately 61 percent (2003 – 63 percent) of the gross administrative costs. At year-end 2004 Tempest employed 13 employees compared to 14 employees at the end of 2003. All senior staff were paid salaries of $100,000-$140,000 plus bonuses. See the AIF for additional details regarding executive compensation.

For the fourth quarter net G&A was $1.08 per boe, versus $4.55 in 2003. The $371,618 (2003 – $1.0 million) variance was largely a result of no capitalization in the fourth quarter of 2003.

Management expects 2005 G&A expenses to remain flat on a boe basis as volume increases offset gross G&A cost increases. Tempest has budgeted higher G&A of $4.9 million for 2005 versus $3.8 million in 2004, with the additional amount reflecting increased staffing and consulting levels to accommodate higher levels of activity. Overhead recoveries and capitalization should be approximately the same as 2004, based on budgeted capital expenditures for 2005. Tempest continues to closely monitor and control these costs and expects to maintain net G&A costs of $1.50-$2.00 per boe produced.

($000s)	**2004**	2003	% Change
Gross	**3,823**	2,726	40
Partner recovery	**(174)**	(186)	(6)
Capitalized	**(1,140)**	(825)	38
Net G&A	**2,509**	1,715	46
Per boe gross ($)	**2.87**	2.82	2
Per boe net ($)	**1.89**	1.79	6

STOCK-BASED COMPENSATION

The adoption of the fair value method of stock option accounting in the first quarter of 2004 resulted in income and retained earnings being restated for 2003 and the recognition of a separate line item expense in 2004. In 2004, and retroactively, Tempest calculates a value for stock options granted and expenses the corresponding amounts over the option vesting period. The weighted average estimate of value for the 40,000 options granted in 2004 was $5.00 (2003 – $3.52) per share. (See MD&A discussion regarding new accounting and regulatory requirements and notes 2 and 3 in the Notes to the Consolidated Financial Statements for additional details.)

	Number of Options Vesting	Average Exercise Price ($)	Expense per Option ($)	Annual Option Expense ($)
2003	780,822	2.67	2.37	1,850,796
2004	884,707	2.92	2.10	1,856,210
2005	548,333	4.00	2.26	1,238,710
2006	120,000	4.96	0.92	110,375
2007	13,333	6.45	4.32	57,560

This table excludes the 440,000 options granted to date in 2005, which will have an estimated impact of approximately $175,000 per quarter for the next three years.

INTEREST EXPENSE

As expected, net interest costs to the Company increased in 2004 with higher levels of bank debt to $0.95 per boe compared to $0.39 in 2003. As Tempest grows and continues to be more active, we anticipate using higher levels of debt and working capital deficiencies. In turn, higher debt will translate to higher interest expense which we expect will be $1.00-$1.50 per boe in 2005. The higher interest costs would in turn reduce earnings.

($000s)	2004	2003	% Change
On debt	**1,184**	383	209
On flow-through	**78**	1	7,700
Interest expense	**1,262**	384	229
Interest income	**3**	12	(76)
Net interest	**1,259**	372	238
Per boe ($)	**0.95**	0.39	144

DEPLETION AND DEPRECIATION

Depreciation and depletion are calculated based upon capital expenditures, production rates and reserves. Tempest recorded $20.3 million (2003 – $12.4 million) or $15.44 per boe (2003 – $12.72 per boe) in depletion and depreciation for the year ended December 31, 2004 on production volumes of 1,329,906 (2003 – 985,045) boe. Costs per each boe discovered were higher in 2004 than in past years due to increased costs arising from the tight supply of services in the industry and Tempest's investment in facilities. Costs include all capital items including facilities which are constructed by the Company to control operating costs and expand land positions. Strong commodity prices allow the Company to develop smaller reserves with lower economic thresholds as they provide positive net present value to the Company.

Tempest estimates depletion on a quarterly basis throughout the year using independent inputs such as reserve and land reports when available. Tempest excludes undeveloped land and seismic and includes salvage value from the capital base in the calculation. In the fourth quarter of 2004 these amounts totaled $22.1 million and when combined with the independent reserves and independent land values, the depletion was calculated at $17.17 per boe.

For 2004, Tempest anticipates that depletion, depreciation and site restoration will be $15-$20 per boe, which is in line with new cost levels we are seeing in the industry.

($000s)	Q4/2004	2004	2003	% Change
Depletion	5,896	**20,327**	12,420	64
Retirement obligation	60	**204**	109	86
Total	5,956	**20,531**	12,569	64
Depletion per boe ($)	17.17	**15.28**	12.61	21
Retirement obligation ($/boe)	0.17	**0.15**	0.11	38
Total ($/boe)	17.34	**15.44**	12.72	21

ASSET RETIREMENT OBLIGATIONS

Tempest adopted the asset retirement obligation method of accounting for its future abandonment obligations in the first quarter of 2004, which involved restating prior years. (See MD&A discussion regarding new accounting and regulatory requirements and notes 2 and 3 in the Notes to the Consolidated Financial Statements for details.) This method records the present value of estimated clean up and restoration costs for all of Tempest's facilities, including well sites and pipelines. The liability amount is increased each reporting period due the passage of time and the amount of accretion is charged to earnings in the period. Tempest expensed $203,745 of accretion in 2004 (2003 – $109,262). The result is a $3.4 million (2003 – $2.1 million) liability on the balance sheet with a similar increase in capital assets.

INCOME AND OTHER TAXES

Tempest expended $51.0 million in capital in 2004 (2003 – $47.5 million) of which $12.0 million had no associated tax pools due to the flow-through share tax pool renouncements. The balance was comprised of $11.0 million relating to the September 2003 renouncement and $1.0 million of expenditures related to the $10.0 million December 2004 flow-through. With budgeted expenditures of $40.0-$50.0 million in 2005, Tempest expects that it will have sufficient tax pools to offset the related 2004 and 2005 current tax liability. Of the budgeted capital, $9.0 million will have no associated tax pools as this represents the unexpended December 31, 2004 balance related to the flow-through share offering which closed on December 13, 2004. Taxes payable beyond 2005 will become a function of commodity prices, production volumes and capital expenditures.

Corporations currently pay a 0.0175 percent Large Corporations Tax (LCT) when their stated capital exceeds $50 million. There was a $120,617 liability in 2004 (2003 – $120,000) and Tempest does not anticipate a significant change in the amount of this tax for 2005. Tax beyond this point will be a function of rates and capital employed.

The provision for income taxes differs from the amount obtained by applying the combined Federal and Provincial income tax rate of 2004 – 38.6 percent (2003 – 40.6 percent) to income before income taxes mainly due to non-deductible Crown charges and resource allowance.

ESTIMATED TAX POOLS

Type ($ millions)	December 31, 2004	December 31, 2003	Rate of Claim (%)
Canadian exploration expense	–	2.9	100
Non-capital loss	–	4.0	100
Canadian development expense	**7.6**	6.5	30
UCC	**27.4**	20.7	20 – 100
Share issue	**2.0**	2.3	20
Canadian oil and natural gas property expense	**18.6**	11.8	10
Total	**55.6***	48.2*	

* This includes tax pool usage required in 2005 to offset $45.5 million (2003 – $20.1 million) of taxable income that is included for financial statement purposes but delayed one year for tax purposes. As well, the 2004 number includes the reduction of $1.0 million (2003 – $5.0 million) of tax pools renounced under flow-through.

EARNINGS

Earnings increased by 331 percent to $4.2 million in 2004 (2003 – $1.0 million) or $0.23 (2003 – $0.06) per basic share. This is after future income taxes of $2.6 million (2003 – $927,620) and $120,617 in current taxes related to LCT (2003 – $120,000). The 65 percent increase in revenues for 2004 was partially offset by the increase in across-the-board costs, as previously discussed.

For 2005, Tempest anticipates that volume increases and firm commodity prices will provide positive earnings growth.

Earnings for 2003 were retroactively restated in 2004 to account for the adoption of the Asset Retirement Obligation change as well as the adoption of the change to stock-based compensation. (See the Notes to the Consolidated Financial Statements.)

	Fourth Quarter Ended December 31, 2004	Fourth Quarter Ended December 31, 2003	**Twelve Months Ended December 31, 2004**	Twelve Months Ended December 31, 2003	% Change
Earnings (loss) ($000s)	531	(1,162)	**4,171**	967	331
Earnings (loss) ($/boe)	1.55	(5.13)	**3.14**	0.98	220
Earnings ($/basic share)	0.03	(0.06)	**0.23**	0.06	283
Earnings ($/diluted share)	0.03	(0.06)	**0.22**	0.06	266

CASH FLOW

Tempest generated cash flow from operations of $28.8 million, up 77 percent from 2003 cash flow of $16.3 million, of which $6.5 million (2003 – $2.6 million) was generated in the fourth quarter. This increased cash flow translated to $1.55 per basic share, which is 60 percent higher than the previous year. The higher cash flow is attributable to the 35 percent increase in production volumes and the 23 percent gain in commodity prices.

Based on our projected production of 4,500-5,000 boe per day, Tempest anticipates 2005 cash flow will be approximately $35.0-$40.0 million or $1.70-$1.90 per basic share. These projections translate into earnings before tax of $7.0-$9.0 million or approximately $0.30-$0.40 per basic share.

	Fourth Quarter Ended December 31 2004	Fourth Quarter Ended December 31, 2003	**Twelve Months Ended December 31, 2004**	Twelve Months Ended December 31, 2003	% Change
Cash flow ($000s)	6,508	2,641	**28,797**	16,275	77
Cash flow per boe ($)	18.95	11.65	**21.65**	16.52	31
Cash flow per basic share ($)	0.35	0.14	**1.55**	0.97	60
Cash flow per diluted share ($)	0.33	0.14	**1.52**	0.97	57

CAPITAL EXPENDITURES

($000s)	Fourth Quarter Ended Dec. 31, 2004	**Year Ended Dec. 31, 2004**	% of Total	Year Ended Dec. 31, 2003	% of Total	Year 2005 Estimated
Drilling and completions	6,502	**20,956**	41	23,002	49	22,000
Equipment and facilities	2,220	**15,804**	31	13,884	29	10,000
Land	759	**5,374**	10	7,185	15	8,000
Acquisitions	–	**6,000**	12	–	–	–
Geological and geophysical	156	**2,828**	6	3,428	7	5,000
Total capital expended	9,637	**50,962**	100	47,499	100	40-50,000

For 2004, Tempest posted finding and development costs on capital spent of $19.29 per proved plus probable boe, compared to $32.81 in 2003. To some extent, the results in both years reflect revisions required as a result of the NI 51-101 reserve reporting regulations.

FINDING AND DEVELOPMENT	2004	2003	LTD
Reserve adds (mboe)	**2,544**	1,447.5	9,647
Capital spent ($ millions)	**51.0**	47.5	163.3
Tax accrual on acquisition ($ millions)	–	–	2.4
Total capital ($ millions)	**51.0**	47.5	165.7
F&D cost on capital ($/boe)	**19.29**	32.81	17.18

Tempest drilled 39 (32.8 net) wells in 2004 compared to 41 (38.2 net) wells in 2003 and at December 31, 2004 had gained an additional 38,333 net acres of undeveloped land. Tempest expended $20.6 million in total capital in the Central Area in 2004, comprised of $6.0 million for the Bon Accord acquisition with the balance allocated to drilling, completion and tie-in of 19 (18.9 net) wells. In the Northern area, Tempest expended $19.4 million to finalize construction of the Otter gathering system and to drill 20 (13.9 net) wells including the development wells which delineated the Company's Keg River light oil discovery.

Tempest's 2005 capital program is estimated to be $40.0-$50.0 million of which $40 million will be funded through cash flow, and the balance from our banking facility, working capital and equity. The bank provides development funds based on the Company's proved reserves from successful exploration and exploitation efforts. The 2005 budget is based on:

- Extensive drilling in the Northern Area for light oil in the first quarter with one or two locations in late summer;
- 20 exploration gas wells in the Central Area identified on new 3-D seismic;
- Five shallow gas wells and five deep gas wells at our West 5 Central Area;
- Three large 3-D seismic programs in the Central Area in the first quarter;
- Completion of the $9.0 million outstanding flow-through obligation, and
- Other exploration.

2004 DRILLING ACTIVITY

	Exploration		Development		Total		Success	W.I.
	Gross	Net	Gross	Net	Gross	Net	%	%
Q1	10.0	9.9	7.0	3.5	17.0	13.4	88	79
Q2	4.0	4.0	–	–	4.0	4.0	100	100
Q3	3.0	2.5	–	–	3.0	2.5	67	83
Q4	10.0	9.9	5.0	3.0	15.0	12.9	93	86
Total	27.0	26.3	12.0	6.5	39.0	32.8	87	84

When a Company follows the full cost method of accounting as Tempest does, the cost of all wells, both successful and unsuccessful are added to the capital base and depleted at the rate of production over the remaining oil and gas reserves. A ceiling test is then employed to ensure that the carrying value of capital assets in the financial statements does not exceed their fair value. For the year ended December 31, 2004 no write-down was required as Tempest's carrying value of capital assets exceeded the undiscounted estimated future net revenue from proved reserves.

In the first quarter of 2004, and for all subsequent quarters and year-end 2004, Tempest applied the new method for calculating the ceiling test as required by accounting standards. (See MD&A discussion regarding new accounting and regulatory requirements.) Had the Company adopted this new method for calculating the ceiling test as required by accounting standards at December 31, 2003, no impairment would have been recognized.

EQUITY

Since January 1, 2005 to the date of the MD&A Tempest has granted 440,000 new stock options at $6.31 to $6.36 and issued 162,335 shares on the exercise of 162,335 outstanding stock options.

On December 13, 2004 Tempest raised $10.0 million in flow-through shares, incurring share issue costs of $689,593 issuing 1,162,791 Class A shares at $8.60 each. The Company renounced tax pools worth $10.0 million (CEE) to the holders of these new flow-through Class A shares effective December 31, 2004. The Company incurred $986,709 up to year-end 2004 and has until year-end 2005 to incur the remaining $9.0 million of CEE on appropriate expenditures.

The Company pays interest to the government on funds that remain unexpended at the end of each month in 2005. Tempest estimates that the majority of the remaining expenditures will be incurred by the end of April 2005 leaving very little for accrued interest costs which would be payable by March 2006. The associated future tax liability entry on the flow-through shares will be recorded in the first quarter of 2005.

On September 15, 2003 Tempest raised $16.0 million in flow-through shares, incurring share issue costs of $1.1 million and issuing an additional 2,285,714 Class A shares at $7.00 each. The Company renounced tax pools worth $16.0 million (CEE) to the holders of the new Class A flow-through shares effective December 31, 2003. The Company incurred $5.0 million up to year-end 2003 and expended the balance of $11.0 million by the end of August 2004, accruing $78,165 of related interest to the government.

Tempest's Class B shares can be converted at the option of the Company at any time up to December 31, 2005. If conversion has not occurred by the close of business on December 31, 2005 the Class B shares become convertible (at the option of the shareholder) into Class A shares on the same basis. Effective February 1, 2006 all remaining Class B shares will automatically be converted to Class A shares.

Tempest's shares were listed on the Venture Stock Exchange on February 9, 2001 and were subsequently listed on the Toronto Stock Exchange on September 4, 2002 under the symbols TMY.A for the Class A shares and TMY.B for the Class B shares.

SHARE CAPITAL

	Class A Shares
Closing December 31, 2003	17,370,319
December 13 @ $8.60 flow-through	1,162,791
Exercise of stock options	527,700
Closing December 31, 2004	19,060,810
Exercise of stock options	162,335
Closing March 4, 2005	19,223,145
Held by management and directors	11%

WEIGHTED SHARES	2004	2003
Weighted Class A shares	**17,536,445**	15,639,092
Weighted Class B shares	**653,476**	653,476
Conversion of Class B shares	**323,319**	463,577
Basic shares outstanding *	**18,513,240**	16,756,145
Stock option dilution (treasury method)	**411,074**	311,277
Weighted diluted shares outstanding	**18,924,314**	17,067,422

* For December 31, 2004 the Class B shares are converted at the year-end Class A share price of $6.69 (2003 – $5.85) and added to the Class A shares to calculate basic shares outstanding.

During 2004 the Company granted 40,000 Class A stock options at $6.45 per share to employees of the Company, 527,700 stock options were exercised and 90,000 stock options were cancelled, bringing the total number of outstanding options at year-end 2004 to 1,499,004 (2003 – 2,076,704). There were 162,335 stock options exercised between January 1, 2005 and March 4, 2005 and an additional 440,000 options granted during that same period.

2004 STOCK OPTION ACTIVITY

Opening	Issued	Exercised	Cancelled	Closing
2,076,704	40,000	527,700	90,000	1,499,004
Average price of $3.45	Average price of $6.45			Average price of $3.69
5.5 years weighted average contractual life				4.8 years weighted average contractual life

CLASS A SHARE TRADING SUMMARY – TORONTO STOCK EXCHANGE – TMY.A

($ except volume)	High	Low	Average	Volume
2004				
Q1	**6.00**	**5.00**	**5.61**	**517,288**
Q2	**5.40**	**4.80**	**5.13**	**840,995**
Q3	**5.85**	**4.75**	**5.40**	**1,047,952**
Q4	**7.19**	**5.60**	**6.63**	**2,073,179**
2004 total	**7.19**	**4.75**	**5.94**	**4,479,414**
Year-end closing price	**6.69**			
2003				
Q1	5.60	4.80	5.21	1,730,515
Q2	5.76	4.25	5.07	1,788,220
Q3	6.13	5.15	5.66	764,398
Q4	5.90	4.91	5.30	840,446
2003 total	6.13	4.25	5.26	5,123,579
Year-end closing price	5.85			
2002				
Q1	4.20	2.95	3.43	174,864
Q2	5.00	3.50	4.10	485,010
Q3	5.00	3.71	4.06	191,239
Q4	5.90	3.70	4.33	1,437,138
2002 total	5.90	2.95	4.19	2,288,221
Year-end closing price	4.75			
2001				
Q1 – listed Feb. 9, 2001	1.90	0.90	1.61	216,229
Q2	3.00	1.65	2.38	464,420
Q3	3.10	2.00	2.58	175,400
Q4	3.25	2.45	2.77	268,650
2001 total	3.25	0.90	2.36	1,124,699
Year-end closing price	2.90			

RELATED PARTY AND OFF BALANCE SHEET TRANSACTIONS

Tempest was not involved in any related party or off balance sheet transactions during the year.

QUARTERLY DATA

	2004				2003			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production								
Total (boe/day)	**3,733**	**4,001**	**3,862**	**2,934**	2,464	2,704	2,929	2,721
Oil (bbls/day)	**1,284**	**1,455**	**1,461**	**1,353**	1,384	1,776	2,003	2,243
Gas (mcf/day)	**14,694**	**15,274**	**14,409**	**9,481**	6,484	5,566	5,556	2,870
% Oil	**34**	**36**	**38**	**46**	56	66	68	83
Financial								
($000s, except per share data)								
Revenue	**14,579**	**15,365**	**15,394**	**10,026**	7,287	7,784	8,698	9,704
Earnings (loss) before tax	**426**	**2,133**	**3,352**	**934**	(1,815)	402	441	2,986
Earnings before tax per share	**0.02**	**0.11**	**0.18**	**0.05**	(0.10)	0.02	0.03	0.18
Earnings (loss) before tax per diluted share	**0.02**	**0.11**	**0.18**	**0.05**	(0.10)	0.02	0.03	0.18
Net earnings (loss)	**531**	**1,058**	**1,626**	**955**	(1,162)	623	(60)	1,566
Net earnings (loss) per share	**0.03**	**0.06**	**0.09**	**0.05**	(0.06)	0.04	–	0.10
Net earnings (loss) per diluted share	**0.03**	**0.06**	**0.09**	**0.05**	(0.06)	0.04	–	0.09
Cash flow	**6,508**	**8,180**	**8,763**	**5,347**	2,641	3,658	3,982	5,994
Cash flow per share	**0.35**	**0.44**	**0.47**	**0.29**	0.14	0.22	0.25	0.37
Cash flow per diluted share	**0.33**	**0.43**	**0.46**	**0.28**	0.14	0.22	0.24	0.36
Capital spent	**9,637**	**12,933**	**4,104**	**24,288**	12,907	11,999	9,358	13,235
Basic shares	**18,860**	**18,579**	**18,730**	**18,637**	18,417	16,612	16,156	16,166
Diluted shares	**19,499**	**18,973**	**18,999**	**18,977**	18,713	16,954	16,436	16,494

The relatively large capital expenditures in Q1, 2004 and the increase in volumes in Q2, 2004 were as a result of the natural gas development at Otter.

RISK, LIQUIDITY AND CAPITAL RESOURCES

The $1.4 million source of funds in the change in non-cash operating working capital was due mainly to higher revenues and therefore increased accounts receivables until those revenues were settled on the 25th day of the following month, as per standard industry practice. The $1.4 million use of funds in the change in non-cash operating working capital was due mainly to lower capital expenditures, offset by a reduction in the number of days that accounts payables were outstanding in the fourth quarter of 2004 versus the fourth quarter of 2003.

Tempest's business plan has been to grow by exploring for oil and natural gas. As an exploration company, Tempest's principle risks are finding and developing economic petroleum reserves efficiently and being able to fund the capital program. Tempest relies on cash flow, bank debt and equity markets to fund its capital programs. Tempest anticipates a $40-$50 million capital program in 2005, with $15-20 million expended in the first quarter. This will be funded by the $40 million of estimated cash flow as well as credit facilities and equity if required. Tempest's credit facility will be reviewed at the end of March and updated based on the new reserve report prepared by the Company's independent evaluation engineers. If any components of the business plan are missing, the Company may not be able to execute the entire business plan.

Tempest mitigates exploration risk by employing a team of highly qualified and experienced professionals to pursue exploration and exploitation activities and to carry out and control the capital spending program. All aspects of exploration projects are reviewed at a very early stage, including: corporate fit, environmental issues, timing, costs and reward potential. Identified risks are addressed and excessive risks are mitigated before any project is approved.

Operational risk is mitigated by having Tempest staff address the continued development of a new or established reservoir, on a go-forward basis, using the same careful and calculated manner that is used to address exploration risk. Reserves are produced based on the amount of capital employed, production practices and reservoir quality. Tempest evaluates reservoir development based on timing and amount of additional capital required and the expected change in production volumes. Finding and development costs are controlled when capital is employed cost-effectively.

The financial risks of commodity prices and interest rates are largely beyond Tempest's control. The Company's approach to managing these risks is to maintain a prudent level of debt and to employ conservative forecasting and budgeting projections. As a guideline for monitoring maximum debt leverage, Tempest uses a 1:1 debt-to-equity ratio or a 1.5 times debt-to-forward cash flow. In order to facilitate the development of Tempest's reserves, the Company has a $35.0 million extendible revolving-credit facility and a $5.0 million operating demand facility. These facilities are with a Canadian chartered banking syndicate. At December 31, 2004, a balance of $24.1 million had been drawn on this facility with an effective bank rate of prime plus 130 basis points. Tempest has a $32.2 million debt and working capital deficiency at the end of 2004 (2003 – $20.9 million). This represents 28 percent of capital, relatively unchanged from the 25 percent of capital in 2003. Tempest anticipates that these amounts will fluctuate based on cash flow and exploration and development activities. Tempest is very mindful of the ongoing liability levels attributed to a working capital deficit. Tempest uses bank lines to facilitate short-term liquidity management and has raised equity to reduce debt leverage and stabilize the balance sheet. Tempest believes that the working capital deficit will continue to grow as the enterprise becomes larger; however, leverage limits will be closely monitored on a debt-to-cash flow basis.

Corporate assets are protected through adequate corporate insurance as well as a proactive approach to all safety and environmental issues.

SENSITIVITY ANALYSIS

Estimated Impact in 2005	$	$/Basic Share
Natural Gas (6:1)		
Change of $0.10Cdn/mcf in average price	299,097	0.01
Change of 1 mmcf/day production	1,686,177	0.08
Oil and NGLs – WTI		
Change of $1.00/bbl in average price	980,445	0.05
Change of 100 bbls/day production	1,325,487	0.07

CRITICAL ACCOUNTING ESTIMATES

Proved Oil and Gas Reserves

Under National Instrument 51-101 (NI 51-101), "proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. (It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.) In accordance with this definition, the level of certainty targeted by the reporting company should result in at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated reserves. In the case of "probable" reserves, which are obviously less certain to be recovered than proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. With respect to the consideration of certainty, in order to report reserves as proved plus probable, the reporting company must believe that there is at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves. The implementation of NI 51-101 has resulted in a more rigorous and uniform standardization of reserve evaluation.

The oil and gas reserve estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's plans. The effect of changes in proved oil and gas reserves on the financial results and position of the Company is described next under depletion expense and impairment of petroleum and natural gas properties.

Depletion Expense

The Company uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether or not the activities funded were successful. The aggregate of net capitalized costs and estimated future development costs, less estimated salvage values, is amortized using the unit-of-production method based on estimated proved oil and gas reserves.

An increase in estimated proved oil and gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

Withheld Costs

Certain costs related to unproved properties may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted.

Impairment of Petroleum and Natural Gas Assets

The Company is required to review the carrying value of all petroleum and natural gas assets for potential impairment. Impairment is indicated if the carrying value of the petroleum and natural gas assets are not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the property, plant and equipment is charged to earnings. The assessment of impairment is dependent on estimates of reserves, production rates, prices, future costs and other relevant assumptions.

Asset Retirement Obligations

The Company is required to provide for future removal and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. The fair value of the liability of $3.4 million (2003 – $2.1 million) for the Corporation's asset retirement obligation is recorded in the period in which it is expected to be incurred between 2006 and 2019, discounted to its present value using the Corporation's four percent credit premium added to the four percent risk-free interest rate and two percent inflation rate. The offset to the liability is recorded in the carrying amount of petroleum and natural gas properties. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

Stock-Based Compensation

The Corporation uses the fair value method for valuing stock option grants. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for grants in 2004: zero dividend yield; expected volatility of 103 percent; risk-free rate of 3.92 percent; and expected life of five years. The following assumptions were used in 2003: zero dividend yield; expected volatility of 94 percent; risk-free rate of 3.6-4.2 percent; and expected life of five years. The weighted average fair value of stock options granted during the year was $5.00 (2003 – $3.52) per option. A zero dividend yield is used as the Company does not issue dividends, the volatility is a calculation based on past trading history and the risk free rate is from the Bank of Canada. An increase in dividends would decrease the option expense and an increase in volatility or the risk free rate would increase the calculated expense.

Legal, Environmental Remediation and Other Contingent Matters

The Company is required to determine whether a loss is probable based on judgment and interpretation of laws and regulations and whether the loss can reasonably be estimated. When the loss is determined, it is charged to earnings.

The Company's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstance.

Income Tax Accounting

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

NEW ACCOUNTING STANDARDS FOR 2004

The following new and amended standards impacted Tempest in 2004 as follows:

Asset Retirement Obligations

Effective January 1, 2004, the Corporation retroactively adopted, with restatement to prior periods, a new accounting standard relating to asset retirement obligations, as outlined in Note 2 in the Notes to the Consolidated Financial Statements. Prior to adopting the standard, the Corporation recognized a provision for future site restoration costs over the life of the oil and gas properties and facilities using a unit-of-production method. As a result of implementation, the liability on the balance sheet for future abandonment costs increased to $2.1 million for 2003 from $0.6 million with the majority of the balance recorded to property, plant and equipment. The transitional provisions of this section require that the standard be applied retroactively with restatement of comparative periods. As a result of the retroactive application, 2003 comparative numbers have been restated to reflect the impact of this standard on the 2004 financial statements. See note 6 in the Notes to the Consolidated Financial Statements for a continuity.

Stock-Based Compensation and Other Stock-Based Payments

Effective January 1, 2004, the Corporation retroactively adopted, with restatement of prior periods, a new accounting standard relating to stock-based compensation. As a result of adopting the new accounting standard, net earnings for the year ended December 31, 2003 decreased by $1,752,520, a $0.10 impact on basic and diluted earnings per share, contributed surplus increased by $1,849,137 and share capital increased $257,243. Opening 2003 retained earnings decreased by $353,860 to reflect the impact of the 2002 stock-based compensation expense, and opening 2004 retained earnings decreased by $2,106,380 to reflect the cumulative impact of 2002 and 2003 stock-based compensation expense. Had the Company adopted this standard earlier, the impact would have been the same as prior periods have been restated to reflect these changes.

Full Cost Accounting

Effective January 1, 2004, the Corporation adopted the new accounting standard relating to full cost accounting. The guideline requires that oil and natural gas assets are evaluated in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre. The carrying amounts are assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount of the cost centre. The adoption of this new policy on January 1, 2004 resulted in no write-down to the carrying value of petroleum and natural gas properties. Prior to January 1, 2004 the ceiling test amount was the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost or market of unproved properties and the cost of major development projects less estimated future costs for administration, financing, site restoration and income taxes.

The Corporation could have adopted this method on December 31, 2003 and had it done so no impairment would have been recognized.

The successful efforts method is the other acceptable method of accounting. Under the successful efforts method, any wells that were unsuccessful would be expensed as incurred.

Accounting for Derivative Instruments and Hedging Activities

The Corporation currently accounts for derivatives using hedge accounting, resulting in unrealized gains or losses on these derivatives not being recognized on the balance sheet. If the Corporation did not elect for hedge accounting, the gain of $395,166 on derivatives would have been recorded at fair value at the balance sheet date and future changes in fair value would be recognized in income.

CONTRACTUAL OBLIGATIONS

As at December 31, 2004 ($000s)	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Additions to property and equipment classified as Canadian Exploration Expense renounced to shareholders under the flow-through share program	$ 9,000	$ 9,000	$ –	$ –	$ –
Payments for office space, related operating expenses and taxes	255	255	–	–	–
Operating leases	517	517	–	–	–
Obligation to issue Class A shares in exchange for Class B shares	6,535	–	Up to 6,535	–	–

In addition, the Company has entered into farm-in agreements in the normal course of its business.

This Management's Discussion and Analysis was dated March 4, 2005.

MANAGEMENT'S REPORT TO SHAREHOLDERS

Management is responsible for the integrity and objectivity of the information contained in this annual report and for the consistency between the financial statements and other financial and operating data contained elsewhere in the report. In the preparation of these statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgements and have been properly reflected. The financial statements have been prepared using policies and procedures established by management and reflect fairly Tempest's financial position, results of operations and cash flow.

Management has established and maintains a system of internal controls which are designed to ensure that financial information is reliable and accurate and to provide assurance that assets are safeguarded from loss or unauthorized use.

KPMG LLP, independent auditors appointed by the shareholders, have examined the consolidated financial statements and Gilbert Laustsen Jung Associates Ltd. have reviewed corporate reserves. Their examination provides an independent view as to the amounts and disclosures in the financial statements.

The Board of Directors has reviewed in detail the financial statements with management and the external auditors. The Board of Directors has approved the financial statements and information as presented in this annual report.

A. Scott Dawson
President and Chief Executive Officer

Douglas N. Penner
Vice President, Finance and Chief Financial Officer

March 4, 2005

AUDITORS' REPORT TO SHAREHOLDERS

We have audited the consolidated balance sheets of Tempest Energy Corp. as at December 31, 2004 and 2003 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

March 4, 2005

CONSOLIDATED BALANCE SHEETS

	December 31, 2004	December 31, 2003
ASSETS		
Current assets:		
Accounts receivable	**$ 6,847,540**	$ 4,547,139
Prepaid expenses and deposits	**248,617**	415,460
	7,096,157	4,962,599
Petroleum and natural gas properties (note 4)	**116,261,646**	84,291,688
	$ 123,357,803	$ 89,254,287
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Outstanding cheques	**$ –**	$ 627,548
Accounts payable and accrued liabilities	**15,117,756**	15,294,522
Bank debt (note 5)	**24,145,439**	9,900,000
	39,263,195	25,822,070
Future income taxes (note 8)	**19,606,659**	17,284,500
Asset retirement obligations (note 6)	**3,384,304**	2,105,719
Shareholders' equity:		
Share capital (note 7)	**51,215,640**	39,155,972
Contributed surplus (note 7)	**2,778,557**	1,947,413
Retained earnings	**7,109,448**	2,938,613
	61,103,645	44,041,998
Commitments (note 9)		
	$ 123,357,803	$ 89,254,287

See accompanying notes to consolidated financial statements.

Approved on behalf of the Board:

A. Scott Dawson
Director

Harley L. Winger
Director

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

	Year Ended December 31, 2004	**Year Ended December 31, 2003**
Revenues:		
Petroleum and natural gas	**$ 55,363,240**	$ 33,473,248
Royalties (net of Alberta Royalty Tax Credit)	**(11,942,054)**	(7,716,219)
	43,421,186	25,757,029
Expenses:		
Operating	**8,605,734**	5,573,468
Transportation	**1,869,347**	1,702,183
Interest	**1,259,299**	372,086
General and administrative	**2,508,621**	1,714,745
Stock-based compensation	**1,801,983**	1,850,796
Depletion, depreciation and accretion	**20,530,750**	12,529,135
	36,575,734	23,742,413
Earnings before income taxes	**6,845,452**	2,014,616
Income taxes (note 8):		
Current	**120,617**	120,000
Future	**2,554,000**	927,620
	2,674,617	1,047,620
Net earnings	**4,170,835**	966,996
Retained earnings, beginning of year, as previously reported	**4,983,256**	2,304,053
Retroactive effect of changes in accounting policy (note 3)	**(2,044,643)**	(332,436)
Retained earnings, beginning of year, as restated	**2,938,613**	1,971,617
Retained earnings, end of year	**$ 7,109,448**	$ 2,938,613
Earnings per share (note 7):		
Basic	**$ 0.23**	$ 0.06
Diluted	**$ 0.22**	$ 0.06

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2004	Year Ended December 31, 2003
Cash provided by (used in):		
Operations:		
Net earnings	**$ 4,170,835**	$ 966,996
Items not involving cash:		
Depletion, depreciation and accretion	**20,530,750**	12,529,135
Future income tax expense	**2,554,000**	927,620
Stock-based compensation	**1,801,983**	1,850,796
Reclamation costs	**(260,367)**	–
Funds from operations	**28,797,201**	16,274,547
Change in non-cash working capital	**1,372,044**	(520,028)
	30,169,245	15,754,519
Financing:		
Issue of Class A shares, net of issue costs	**10,856,988**	15,449,953
Bank debt	**14,245,439**	9,900,000
	25,102,427	25,349,953
Investments:		
Petroleum and natural gas properties	**(50,961,756)**	(47,499,290)
Change in non-cash working capital	**(3,682,368)**	3,599,202
	(54,644,124)	(43,900,088)
Increase (decrease) in cash	**627,548**	(2,795,616)
Cash (outstanding cheques), beginning of year	**(627,548)**	2,168,068
Cash (outstanding cheques), end of year	**$ –**	$ (627,548)

Cash is defined as cash and cash equivalents.

See accompanying notes to consolidated financial statements.

Years ended December 31, 2004 and 2003

1. INCORPORATION

Tempest Energy Corp. (the "Corporation") is incorporated under the laws of the Province of Alberta.

2. SIGNIFICANT ACCOUNTING POLICIES

(a) Consolidation

The consolidated financial statements include the accounts of the Corporation and its wholly-owned subsidiaries and a partnership. All inter-entity transactions and balances have been eliminated.

(b) Petroleum and natural gas properties

The Corporation's activities are related to acquisition of, exploration for and development of petroleum and natural gas properties. The Corporation follows the full cost method of accounting for petroleum and natural gas operations.

All costs of exploring for and developing petroleum and natural gas properties and related reserves are capitalized into a cost centre. Such costs include those related to lease acquisition, geological and geophysical activities, lease rentals on non-producing properties, drilling of productive and non-productive wells, tangible production equipment, asset retirement costs, and that portion of general and administrative expenses directly attributable to exploration and development activities. Proceeds received from the disposal of properties are normally deducted from the full cost pool without recognition of a gain or loss. When a significant portion of properties is sold, resulting in a change to the depletion rate of 20% or more, a gain or loss is recorded and reflected in the statement of operations.

Costs of acquiring unproved properties are initially excluded from the full cost pool and are assessed yearly to ascertain whether impairment has occurred. When proved reserves are assigned to the property or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the full cost pool. Depletion of petroleum and natural gas properties and depreciation of production equipment are calculated using the unit-of-production method based upon estimated proved reserves, before royalties, as determined by an independent engineer. For purposes of the calculation, natural gas reserves and production are converted to equivalent volumes of petroleum based upon relative energy content.

Petroleum and natural gas properties are evaluated in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre.

The carrying amounts are assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount of the cost centre. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects of the cost centre. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

A portion of the Corporation's exploration and development activities are conducted jointly with others and, accordingly, the financial statements reflect only the Corporation's proportionate interest in such activities.

(c) Cash and cash equivalents

Cash and cash equivalents are comprised of cash and all investments that are highly liquid in nature and generally have a maturity date of three months or less.

(d) Asset retirement obligations

The Corporation uses the asset retirement obligation method of recording the future cost associated with removal, site restoration and asset retirement costs. The fair value of the liability for the Corporation's asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using the Corporation's credit adjusted risk-free interest rate and the corresponding amount is recognized by increasing the carrying amount of petroleum and natural gas properties. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

(e) Future income taxes

The Corporation uses the liability method for calculating future income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and the carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using the currently enacted, or substantively enacted tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

(f) Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. Future tax liabilities and share capital are adjusted by the estimated cost of the renounced tax deductions when the expenditures are renounced.

(g) Stock-based compensation plans

The Corporation uses the fair value method for valuing stock option grants. Under this method, compensation cost attributable to all share options granted is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of the stock options, consideration received together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

The Corporation has not incorporated an estimated forfeiture rate for stock options that will not vest, rather, the Corporation accounts for actual forfeitures as they occur.

(h) Revenue recognition

Petroleum and natural gas revenues are recognized when the title and risks pass to the purchaser.

(i) Per share amounts

Basic per share amounts are calculated using the weighted average number of Class A and Class B common shares outstanding during the year. Class B common shares are converted to Class A common shares at $10 divided by the greater of $1 and the Class A market price for the period. Diluted per share amounts are calculated based on the treasury stock method. The weighted average number of shares is adjusted for the dilutive effect of options. The dilutive effect of options uses proceeds received on exercise of options to purchase Class A shares at the average price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

(j) Measurement uncertainty

The amounts recorded for depletion, depreciation and amortization of petroleum and natural gas properties and equipment and the provision for asset retirement obligations and abandonment costs are based on estimates. The ceiling test is based on estimates of reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

(k) Financial instruments

The Corporation uses, from time to time, derivative financial instruments to manage exposure related to changes in oil and natural gas commodity prices. They are not used for trading or speculative purposes.

The Corporation formally documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balances sheet or to specific firm commitments or anticipated transactions.

The Corporation also formally assesses, both at the hedge's inception and on a ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. For cash flow hedges, effectiveness is achieved if the changes in the cash flows of the derivative substantially offset the changes in the cash flows of the hedged position and the timing of the cash flows is similar. Effectiveness for fair value hedges is achieved if the fair value of the derivative substantially offsets changes in the fair value attributable to the hedged item. In the event that a derivative does not meet the designation or effectiveness criterion, the gain or loss on the derivative is recognized in income. If a derivative that qualifies as a hedge is settled early, the gain or loss at settlement is deferred and recognized when the gain or loss on the hedged transaction is recognized. Premiums paid or received with respect to derivatives that are hedges are deferred and amortized to income over the term of the hedge.

Realized gains or losses on changes in oil and natural gas commodity prices are recognized in income in the same period and in the same financial statement category as the income or expense arising from corresponding commodity swap contracts (see note 10).

(l) Comparative figures

Certain comparative figures have been reclassified to conform with current year's presentation.

3. CHANGES IN ACCOUNTING POLICY

Effective January 1, 2004, the Corporation adopted the new accounting standard relating to full cost accounting. The adoption of this new policy on January 1, 2004 resulted in no write-down to the carrying value of petroleum and natural gas properties. Prior to January 1, 2004 the ceiling test amount was the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost or market of unproved properties and the cost of major development projects less estimated future costs for administration, financing, site restoration and income taxes.

Effective January 1, 2004, the Corporation retroactively adopted, with restatement to prior periods, a new accounting standard relating to asset retirement obligations, as outlined in note 2. Prior to adopting the standard, the Corporation recognized a provision for future site restoration costs over the life of the oil and gas properties and facilities using a unit of production method. The effect of the adoption is presented below as increases (decreases):

BALANCE SHEETS	2003	2002
Asset retirement costs, included in petroleum and natural gas properties	$ 1,527,721	$ 1,075,681
Asset retirement obligations	2,105,719	1,159,545
Provision for future site restoration costs	(639,735)	(287,277)
Retained earnings	$ 61,737	$ 21,424

STATEMENT OF OPERATIONS	2003
Accretion expense	$ 109,262
Depletion and depreciation on asset retirement costs	202,883
Amortization of estimated future removal and site restoration liability	(352,458)
Net earnings impact	$ 40,313
Earnings per share – basic	$ –
Earnings per share – diluted	$ 0.01

Effective January 1, 2004, the Corporation retroactively adopted, with restatement of prior periods, a new accounting standard relating to stock-based compensation. As a result of adopting the new accounting standard, net earnings for the year ended December 31, 2003 decreased by $1,752,520, a $0.10 impact on basic and diluted earnings per share, contributed surplus increased by $1,849,137 and share capital increased $257,243. Opening 2003 retained earnings decreased by $353,860 to reflect the impact of the 2002 stock-based compensation expense, and opening 2004 retained earnings decreased by $2,106,380 to reflect the cumulative impact of 2002 and 2003 stock-based compensation expense.

4. PETROLEUM AND NATURAL GAS PROPERTIES

	Cost	Accumulated Depletion	Net Book Value
2004			
Petroleum and natural gas properties	**$ 158,044,274**	**$ 41,782,628**	**$ 116,261,646**
2003			
Petroleum and natural gas properties	$ 105,747,311	$ 21,455,623	$ 84,291,688

During 2004, the Corporation capitalized $1,140,370 (2003 – $824,555) of overhead-related costs to petroleum and natural gas properties.

Costs associated with unproven properties excluded from costs subject to depletion for 2004 totaled $22,100,000 (2003 – $20,200,000).

The Corporation performed a ceiling test calculation at December 31, 2004 to assess the recoverable value of the property, plant and equipment and other assets. The oil and gas future prices are based on the January 1, 2005 commodity price forecast of our independent reserve evaluators. The following table summarizes the benchmark prices used in the ceiling test calculation.

	WTI Oil (US$/bbl)	Foreign Exchange Rate	WTI Oil (Cdn$/bbl)	Tempest Oil Price (Cdn$/bbl)	AECO Gas (Cdn$/mcf)	Tempest Gas Price (Cdn$/mcf)
2005	$ 42.00	$ 0.82	$ 51.22	$ 43.90	$ 6.60	$ 6.37
2006	40.00	0.82	48.78	43.08	6.35	6.12
2007	38.00	0.82	46.34	41.59	6.15	5.91
2008	36.00	0.82	43.90	39.42	6.00	5.76
2009	34.00	0.82	41.46	37.18	6.00	5.76
2010	33.00	0.82	40.24	35.95	6.00	5.76
2011	33.00	0.82	40.24	35.81	6.00	5.75
2012	33.00	0.82	40.24	35.74	6.00	5.75
2013	33.50	0.82	40.85	35.95	6.10	5.85
2014	34.00	0.82	41.46	36.49	6.20	5.95
2015	34.50	0.82	42.07	36.67	6.30	6.05
2016	35.19	0.82	42.91	37.22	6.43	6.20

5. BANK DEBT

The Corporation has a $35,000,000 extendible revolving credit facility and a $5,000,000 operating demand facility. These facilities are with a Canadian chartered banking syndicate and bear interest at bank prime rates adjusted quarterly based on debt to cash flow ratios as defined in the agreement. The credit facilities are secured by a first fixed and floating charge debenture in the minimum face amount of $75,000,000 and a general security agreement. A semi-annual re-determination of the borrowing base will occur on or before March 31 and November 30 of each year. Letters of credit amounting to $361,000 are held against the operating demand facility. As at December 31, 2004, a balance of $24,145,439 had been drawn on this facility with an effective rate of 5.55 percent at December 31, 2004.

Interest paid during the year was $1,079,556 (2003 – $390,682).

6. ASSET RETIREMENT OBLIGATIONS

The Corporation's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Corporation estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations is approximately $5,900,000. The majority of the costs will be incurred between 2006 and 2019. A credit-adjusted risk free rate of eight percent was used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	2004	2003
Balance, beginning of year	**$ 2,105,719**	$ 1,159,545
Accretion expense	**203,745**	109,262
Liabilities incurred	**1,335,207**	836,912
Restoration costs	**(260,367)**	–
Balance, end of year	**$ 3,384,304**	$ 2,105,719

7. SHARE CAPITAL

(a) Authorized

Unlimited number of preferred shares.

Unlimited number of voting Class A shares.

Unlimited number of voting Class B shares, convertible at the option of the Corporation at any time after December 31, 2003 and before December 31, 2005, into Class A shares. The fraction is calculated by dividing $10 by the greater of $1 and the then current market price of Class A shares. If conversion has not occurred by the close of business on December 31, 2005, the Class B shares become convertible at the option of the shareholder into Class A shares on the same basis. Effective February 1, 2006, all remaining Class B shares will automatically be converted to Class A shares.

(b) Issued and outstanding

	Number of Shares	Amount
Class A shares		
Balance, December 31, 2002	14,737,933	$ 25,476,187
For cash pursuant to flow-through share offering	2,285,714	15,999,998
Tax effect of flow-through shares	–	(6,028,799)
Share issue costs	–	(1,064,910)
Tax effect of the share issue costs	–	381,131
For cash on exercise of share options	346,672	514,865
Stock-based compensation	–	257,243
Balance, December 31, 2003	17,370,319	35,535,715
For cash pursuant to flow-through share offering	1,162,791	10,000,003
Share issue costs	–	(689,593)
Tax effect of share issue costs	–	231,841
For cash on exercise of share options	527,700	1,546,578
Stock-based compensation	–	970,839
Balance, December 31, 2004	**19,060,810**	**$ 47,595,383**
Class B shares		
Balance, December 31, 2003 and 2004	653,476	$ 3,620,257
Total share capital on December 31, 2004		**$ 51,215,640**

(c) Share option plan

Under the Corporation's share option plan it may grant options to its employees for up to 1,726,749 shares of Class A shares of which 40,000 were granted in 2004. The exercise price of each option equals the market price of the Corporation's stock on the date of grant and options have varying terms of five to ten years and vest one-third per year over three years.

	2004		2003	
	Number of Options	**Weighted Average Exercise Price**	Number of Options	Weighted Average Exercise Price
Stock options outstanding, beginning of year	**2,076,704**	**$ 3.45**	2,116,867	$ 2.92
Granted	**40,000**	**6.45**	320,000	4.77
Exercised	**(527,700)**	**2.93**	(346,672)	1.49
Cancelled or expired	**(90,000)**	**3.77**	(13,491)	3.07
Stock options outstanding, end of year	**1,499,004**	**$ 3.69**	2,076,704	$ 3.45
Exercisable at year-end	**817,337**	**$ 3.25**	468,372	$ 3.46

The following table summarizes information about the fixed stock options outstanding at December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (years)	Number Exercisable	Weighted Average Exercise Price
$ 0.40	141,670	$ 0.40	1.0	141,670	$ 0.40
$ 2.86 – $ 2.90	5,000	2.90	2.0	5,000	2.90
$ 3.60 – $ 5.20	1,312,334	3.97	5.2	670,667	3.86
$ 6.45	40,000	6.45	4.9	–	–
	1,499,004	$ 3.69	4.8	817,337	$ 3.25

(d) Stock-based compensation

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for grants in 2004: zero dividend yield; expected volatility of 103 percent; risk free rate of 3.92 percent; and expected life of five years. The following assumptions were used in 2003: zero dividend yield; expected volatility of 94 percent; risk-free rate of 3.6-4.2 percent; and expected life of five years. The weighted average fair value of stock options granted during the year was $5.00 (2003 – $3.52) per option.

(e) Contributed surplus

Balance, December 31, 2002	$ 353,860
Compensation expense	1,850,796
Exercise of share options	(257,243)
Balance, December 31, 2003	1,947,413
Compensation expense	1,856,210
Exercise of share options	(970,839)
Cancellation of share options	(54,227)
Balance, December 31, 2004	**$ 2,778,557**

(f) Per share amounts

Per share amounts have been calculated using the weighted average number of shares outstanding. The weighted average shares outstanding for the year ended December 31, 2004 were 18,513,240 (2003 – 16,756,145).

In computing diluted per share amounts, 411,074 (2003 – 311,277) shares were added to the weighted average number of shares outstanding during the year ended December 31, 2004 for the dilutive effect of employee stock options.

In 2004, options to purchase 40,000 (2003 – 1,169,000) common shares were not included in the computation because they were anti-dilutive.

8. INCOME TAXES

The provision for income taxes differs from the amount obtained by applying the combined Federal and Provincial income tax rate of 2004 – 38.6 percent (2003 – 40.6 percent) to income before income taxes. The difference relates to the following items:

	2004	2003
Statutory tax rate	**38.6%**	40.6%
Computed "expected" income tax expense	**$ 2,642,344**	$ 817,934
Non-deductible Crown charges and other expenses	**2,546,187**	1,741,171
Resource allowance	**(2,124,520)**	(965,372)
Alberta Royalty Tax Credit	**(147,278)**	(203,100)
Stock-based compensation	**695,926**	751,423
Future tax rate reduction	**(297,510)**	(1,191,780)
Revisions to tax pools	**(602,200)**	–
Other	**(158,949)**	(22,656)
Future income taxes	**2,254,000**	927,620
Capital tax	**120,617**	120,000
	$ 2,674,617	$ 1,047,620

The components of the net future income tax liability at December 31, 2004 and 2003 are as follows:

	2004	2003
Future tax liabilities		
Petroleum and natural gas assets	**$ 24,884,619**	$ 19,930,294
Future tax assets		
Asset retirement obligations	**(1,137,803)**	(221,476)
Share issue costs	**(755,816)**	(836,476)
Non-capital losses	**(3,384,341)**	(1,587,842)
	(5,277,960)	(2,645,794)
Future income tax liability	**$ 19,606,659**	$ 17,284,500

Non-capital losses of $7,900,000 will expire between 2009 and 2011.

Taxes paid during the year were $196,557 (2003 – $89,276).

9. COMMITMENTS

(a) Pursuant to the flow-through share offering which closed on December 13, 2004, the Corporation issued 1,162,791 Class A common shares for gross proceeds of $10,000,003. The Corporation renounced $10,000,003 to Class A shareholders, effective December 31, 2004. The Corporation has incurred $986,709 to December 31, 2004 and has until December 31, 2005 to expend $9,013,294 on qualified expenditures.

On September 15, 2003, the Corporation issued 2,285,714 flow-through Class A common shares for gross proceeds of $15,999,998. During 2004, the Corporation incurred the remaining $11,049,855 of eligible exploration expenditures to satisfy the terms of the flow-through share offering.

(b) Future minimum lease payments relating to operating lease commitments are:

2005	$ 771,925
	$ 771,925

10. FINANCIAL INSTRUMENTS

(a) Commodity price risk management

In July 2004 the Corporation entered into a natural gas hedging transaction for 5,000 gigajoules per day for the period August 2004 to July 2005. This transaction consisted of the purchase of a $6.21 per gigajoule put and an $8.68 per gigajoule call and the sale of a $7.00 per gigajoule call. The Corporation received net settlement payments of $73,494 during the year ended December 31, 2004 which are included in petroleum and natural gas revenues. The Corporation would have received $395,166 if the hedge had been settled at December 31, 2004.

(b) Foreign currency exchange risk

The Corporation is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar-denominated prices.

(c) Credit risk

A substantial portion of the Corporation's accounts receivable are with customers and joint venture partners in the oil and natural gas industry and are subject to normal industry credit risks. Purchasers of the Corporation's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

(d) Interest rate risk

The Corporation is exposed to interest rate risk to the extent that bank debt is at a floating rate of interest.

(e) Fair value of financial instruments

The fair values of accounts receivable, prepaid expenses and deposits and accounts payable and accrued liabilities approximate their carrying values due to their short-terms to maturities. The Corporation's bank debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying value.

CORPORATE INFORMATION

Directors

A. Scott Dawson[1,2]
President and Chief Executive Officer
Tempest Energy Corp.
Calgary, Alberta

Ken Faircloth[1,2,3]
Retired Oil Analyst
Calgary, Alberta

Harley L. Winger[1,3]
Partner
Burstall Winger LLP
Calgary, Alberta

Ken Woolner[2,3]
President and Chief Executive Officer
Lightning Energy Ltd.
Calgary, Alberta

[1] Audit Committee Member
[2] Reserve Committee Member
[3] Compensation Committee Member

Officers

A. Scott Dawson
President and Chief Executive Officer

Gerald R. Costigan
Vice President, Exploration

Douglas N. Penner
Vice President, Finance and
Chief Financial Officer

Corporate Secretary

Roger O. MacLeod
Burstall Winger LLP
Calgary, Alberta

Head Office

#2800, 500 – 4th Avenue S.W.
Calgary, Alberta
T2P 2V6
Phone: (403) 262-2936
Fax: (403) 262-3924

Legal Counsel

Burstall Winger LLP
Calgary, Alberta

Auditors

KPMG LLP
Calgary, Alberta

Evaluation Engineers

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

Banker

Syndicate led by CIBC
Calgary, Alberta

Transfer Agent

Computershare Investor Services
Calgary, Alberta

Stock Exchange Listing

Toronto Stock Exchange
Symbols: TMY.A, TMY.B

Investor Relations Contact

A. Scott Dawson
President and Chief Executive Officer
Phone: (403) 262-2936
Email: sdawson@tempestenergy.com
Website: www.tempestenergy.com

Abbreviations

bbl	barrel
bbls/day	barrels per day
mbbls	thousand barrels
boe	barrels of oil equivalent
boe/day	barrels of oil equivalent per day
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mmbtu	million British thermal units
mmcf	million cubic feet
NGLs	natural gas liquids
bcf	billion cubic feet

Annual and Special Meeting

The annual and special meeting will be held on Thursday, May 19, 2005, at 10.00 a.m.
Strand/Tivoli Room of the Metropolitan Centre, 333 – 4th Avenue S.W., Calgary, Alberta.

Designed and produced by MERLIN EDGE Inc. www.merlinedge.com Printed in Canada

Tempest
ENERGY CORP.

2800, 500 – 4th Avenue S.W. Calgary, Alberta T2P 2V6
Phone: (403) 262-2936 Fax: (403) 262-3924
www.tempestenergy.com